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United States Nuclear Regulatory Commission
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NUREG-2102

Safety Evaluation Report

Related to the License Renewal of Hope Creek Generating Station

Docket Number 50-354

PSEG Nuclear, LLC

Office of Nuclear Reactor Regulation

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ABSTRACT

This safety evaluation report (SER) documents the technical review of the Hope Creek Generating Station (HCGS), license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated August 18, 2009, PSEG Nuclear, LLC (PSEG or the applicant) submitted the LRA in accordance with Title 10, Part 54, of the Code of Federal Regulations, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." PSEG requests renewal of the operating license (Facility Operating License Number NPF-57) for a period of 20 years beyond the current expiration at midnight April 11, 2026.

HCGS is located approximately 40 miles from Philadelphia, Pennsylvania, and 8 miles from Salem, New Jersey. The NRC issued the construction permit on November 4, 1974, and the operating license for HCGS on July 25, 1986. The unit is a Mark 1 boiling-water reactor design. General Electric Company supplied the nuclear steam supply system, and Bechtel Power Corporation and Bechtel Construction originally designed and constructed the balance of plant aspects. The licensed power output of the unit is 3,840 megawatt thermal with a gross electrical output of approximately 1,268 megawatt electric.

This SER presents the status of the staff's review of information submitted through May 19, 2011, the cutoff date for consideration in this SER. The staff did not identify any open items before the staff made a final determination. SER Section 6.0 provides the staff's final conclusion of the LRA review.

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ABBREVIATIONS

AC	alternating current
ACAR	aluminum conductor, aluminum-alloyed reinforced
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACSR	aluminum conductor steel reinforced
ADAMS	Agencywide Document Access and Management System
ADV	atmospheric dump valve
AERM	aging effect requiring management
AFW	auxiliary feedwater
AISC	American Institute of Steel Construction
AMP	aging management program
AMR	aging management review
ANSI	American National Standards Institute
ART	adjusted reference temperature
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
B&PV	Boiler and Pressure Vessel
B&W	Babcock & Wilcox
BMI	bottom mounted instrumentation
BOP	balance of plant
BTP	branch technical position
BWR	boiling-water reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Project
CASS	cast austenitic stainless steel
CB&I	Chicago Bridge and Iron
CBF	cycle-based fatigue

CCW	component cooling water
CCCW	closed-cycle cooling water
CEA	control element assembly
CETNA	core exit thermocouple nozzle assembly
CFR	Code of Federal Regulations
CLB	current licensing basis
CMAA	Crane Manufacturers Association of America
CO2	carbon dioxide
CRD	control rod drive
CRDM	control rod drive mechanism
CRGT	control rod guide tube
CS	containment spray
CST	condensate storage tank
Cu	copper
CUF	cumulative usage factor
CVCS	chemical and volume control
CVUSE	Charpy upper-shelf energy
CW	circulating water
DBA	design-basis accident
DBD	design-basis document
DBE	design-basis event
DC	direct current
EAF	environmentally-assisted fatigue
ECCS	emergency core cooling system
ECP	electrochemical corrosion potential
EDG	emergency diesel generator
EFPY	effective full-power year
EHC	electro-hydraulic control

EMA	equivalent margin analysis
EN	shelter or protection
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ER	Environmental Report (Applicant's Environmental Report Operating License Renewal Stage)
ESF	engineered safety features
EVT	enhanced visual testing
FAC	flow accelerated corrosion
Fen	environmental fatigue life correction factor
FERC	Federal Energy Regulatory Commission
FLB	flood barrier
FLT	filtration
FMP	Fatigue Monitoring Program
FR	Federal Register
FRV	feedwater regulating valve
FRVS	filtration, recirculation, and ventilation system
ft-lb	foot-pound
FW	feedwater
FWST	fire water storage tank
GALL	Generic Aging Lessons Learned Report
GDC	general design criteria or general design criterion
GEIS	Generic Environmental Impact Statement
GL	generic letter
GSI	generic safety issue
H2	hydrogen
HCGS	Hope Creek Generating Station

HELB	high-energy line break
HEPA	high-efficiency particulate air
HPCI	high-pressure coolant injection
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning
HWC	hydrogen water chemistry
HX	heat exchanger
I&C	instrumentation and controls
IA	instrument air
IASCC	irradiation-assisted stress-corrosion cracking
ID	inside diameter
ID IGA	inside diameter intergranular attack
IEEE	Institute of Electrical and Electronics Engineers
IGA	intergranular attack
IGSCC	intergranular stress-corrosion cracking
ILRT	integrated leak rate testing
IN	information notice
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
ISG	interim staff guidance
ISI	inservice inspection
ISP	integrated surveillance program
ksi	thousands of pounds per square inch
KV or kV	kilovolt
LBB	leak before break
LCO	Limited Condition Operation
LLRT	local leak-rate test
LOCA	loss of coolant accident

LPCI	low-pressure coolant injection
LPRM	local power range monitor
LRA	license renewal application
MB	missile barrier
MC	metal containment
MELB	medium-energy line break
MFW	main feedwater
Mg/L	milligrams per liter
MIC	microbiologically-influenced corrosion
MIRVSP	master integrated reactor vessel surveillance program
MOV	motor-operated valve
mph	miles per hour
MS	main steam
MSIP	Mechanical Stress Improvement
MSIV	main steam isolation valve
MWe	megawatts-electric
MWt	megawatts-thermal
n/cm^2	neutrons per square centimeter
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NESC	National Electrical Safety Code
NFPA	National Fire Protection Association
Ni	nickel
NMCA	noble metals chemical addition
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSSS	nuclear steam supply system

NWC	normal water chemistry
O_2	oxygen
OBE	operating basis earthquake
OCCW	open-cycle cooling water
OD IGA	outside-diameter intergranular attack
ODSCC	outside-diameter stress-corrosion cracking
OI	open item
OTSG	once-through steam generator
P&ID	piping and instrumentation diagram
PAB	primary auxiliary building
PB	pressure boundary
PBD	program basis document
PDI	Performance Demonstration Initiative
pH	potential of hydrogen
PMH	probable maximum hurricane
PoF	probability of failure
PORV	power-operated relief valve
ppm	parts per million
PSEG	PSEG Nuclear, LLC
psi	pounds per square inch
PSPM	periodic surveillance and preventive maintenance
P-T	pressure-temperature
PTS	pressurized thermal shock
PUAR	plant unique analysis report
PVC	polyvinyl chloride
PW	primary water makeup
PWR	pressurized water reactor
PWSCC	primary water stress-corrosion cracking

QA	quality assurance
QAP	quality assurance program
RAI	request for additional information
RAMA	Radiation Analysis Modeling Application
RCCA	rod cluster control assembly
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	regulatory guide
RHR	residual heat removal
RI-ISI	risk informed-inservice inspection
RM	radiation monitoring
RO	refueling outage
RPV	reactor pressure vessel
RTNDT	reference temperature nil-ductility transition
RTPTS	reference temperature for pressurized thermal shock
RTD	resistance temperature detector
RV	reactor vessel
RVCH	reactor vessel closure head
RVI	reactor vessel internal
RVID	Reactor Vessel Integrity Database
RVLIS	reactor vessel level indication system
RW	river water
RWCU	reactor water cleanup
RWST	refueling water storage tank
SA	stress allowable
SACS	safety auxiliaries cooling system

Salem	Salem Nuclear Generating Station
SAP	Systems, Applications, and Products in Data Processing
SBF	stress-based fatigue
SBO	station blackout
SC	structure and component
SCC	stress-corrosion cracking
SE	safety evaluation
SER	safety evaluation report
SFP	spent fuel pool
SFPC	spent fuel pit/pool cooling
SG	steam generator
SGBD	steam generator blowdown
SHE	standard hydrogen electrode
SI	safety injection
SLC	standby liquid control
SMP	structures monitoring program
SO_2	sulfur dioxide
SOC	statement of consideration
SOV	solenoid-operated valve
SPU	stretch power uprate
SRP-LR	Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants
SRV	safety relief valve
SSC	system, structure, and component
SSE	safe-shutdown earthquake
SSFS	safety system function sheets
SW	service water
TAN	total acid number
TBN	total base number
TIP	transversing in-core probe

TLAA	time-limited aging analysis
TOC	total organic carbon
TS	technical specification(s)
TSC	technical support center
UFSAR	updated final safety analysis report
USE	upper-shelf energy
UT	ultrasonic testing
UV	ultraviolet
VCT	volume control tank
VFLD	vessel flange leak detection
VHP	vessel head penetration
VT	visual testing
Yr	year
Zn	zinc
1/4 T	one-fourth of the way through the vessel wall measured from the internal surface of the vessel

SECTION 1

INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the license renewal application (LRA) for Hope Creek Generating Station (HCGS), as filed by PSEG Nuclear, LLC (PSEG or the applicant). By letter dated August 18, 2009, PSEG submitted its application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the HCGS operating license for an additional 20 years. The NRC staff (the staff) prepared this report to summarize the results of its safety review of the LRA for compliance with Title 10, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," of the *Code of Federal Regulations* (10 CFR Part 54). The NRC project manager for the license renewal review is Bennett M. Brady. Dr. Brady may be contacted by telephone at 301-415-2981 or by electronic mail at Bennett.Brady@nrc.gov. Alternatively, written correspondence may be sent to the following address:

Division of License Renewal
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
Attention: Bennett M. Brady, Mail Stop O11-F1

In its August 18, 2009, submission letter, the applicant requested renewal of the operating license issued under Section 103 (Operating License No. NPF-57) of the Atomic Energy Act of 1954, as amended, for a period of 20 years beyond the current expiration at midnight April 11, 2026. HCGS is located approximately 40 miles from Philadelphia, Pennsylvania, and 8 miles from Salem, New Jersey. The NRC issued the construction permit on November 4, 1974. The NRC issued the operating license for HCGS on July 25, 1986. The unit is a Mark 1 boiling-water reactor (BWR) design. General Electric Company supplied the nuclear steam supply system, and Bechtel Power Corporation and Bechtel Construction originally designed and constructed the balance of plant aspects. The licensed power output of the unit is 3,840 megawatt thermal with a gross electrical output of approximately 1,268 megawatt electric. The updated final safety analysis report (UFSAR) shows details of the plant and the site.

The license renewal process consists of two concurrent reviews, a technical review of safety issues and an environmental review. The NRC regulations in 10 CFR Part 54 and 10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions," respectively, set forth requirements for these reviews. The safety review for the HCGS license renewal is based on the applicant's LRA and on its responses to the staff's requests for additional information (RAIs). The applicant supplemented the LRA and provided clarifications through its responses to the staff's RAIs in audits, meetings, and docketed correspondence. Unless otherwise noted, the staff reviewed and considered information submitted through May 19, 2011. The public may view the LRA and all pertinent information and materials, including the UFSAR, at the NRC Public Document Room, located on the first floor of One White Flint North, 11555 Rockville Pike, Rockville, MD 20852-2738 (301-415-4737 / 800-397-4209), and at Salem Free Library, 112 West Broadway, Salem, NJ 08079. In addition, the public may find the LRA, as well as materials related to the license renewal review, on the NRC Web site at http://www.nrc.gov.

This SER summarizes the results of the staff's safety review of the LRA and describes the technical details considered in evaluating the safety aspects of the unit's proposed operation for an additional 20 years beyond the term of the current operating license. The staff reviewed the LRA in accordance with NRC regulations and the guidance in NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), dated September 2005.

SER Sections 2 through 4 address the staff's evaluation of license renewal issues considered during the review of the application. SER Section 5 is reserved for the report of the Advisory Committee on Reactor Safeguards (ACRS). The conclusions of this SER are in Section 6.

SER Appendix A is a table showing the applicant's commitments for renewal of the operating license. SER Appendix B is a chronology of the principal correspondence between the staff and the applicant regarding the LRA review. SER Appendix C is a list of principal contributors to the SER, and Appendix D is a bibliography of the references in support of the staff's review.

In accordance with 10 CFR Part 51, and as part of the environmental review, the staff prepared a draft plant-specific supplement to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS)." Issued separately from this SER, this supplement discusses the environmental considerations for the license renewal of HCGS along with those of Salem Nuclear Generating Station, Units 1 and 2. The staff issued the draft Supplement 45 to NUREG-1437 in October 2010. After considering comments on the draft, the staff published the final, plant-specific GEIS Supplement 45 in March 2011.

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 and 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, rather than on technical limitations; however, some individual plant and equipment designs may have been engineered based on an expected 40-year service life.

In 1982, the staff anticipated interest in license renewal and held a workshop on nuclear power plant aging. This workshop led the NRC to establish a comprehensive program plan for nuclear plant aging research. From the results of that research, a technical review group concluded that many aging phenomena are readily manageable and pose no technical issues precluding life extension for nuclear power plants. In 1986, the staff published a request for comment on a policy statement that would address major policy, technical, and procedural issues related to license renewal for nuclear power plants.

In 1991, the staff published 10 CFR Part 54, the License Renewal Rule (Volume 56, page 64943, of the *Federal Register* (56 FR 64943), dated December 13, 1991). The staff participated in an industry-sponsored demonstration program to apply 10 CFR Part 54 to a pilot plant and to gain the experience necessary to develop implementation guidance. To establish a scope of review for license renewal, 10 CFR Part 54 defined age-related degradation unique to license renewal; however, during the demonstration program, the staff found that adverse aging effects on plant systems and components are managed during the period of initial license and that the scope of the review did not allow sufficient credit for management programs, particularly the implementation of 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” which regulates management of plant-aging phenomena. As a result of this finding, the staff amended 10 CFR Part 54 in 1995. Published on May 8, 1995, in Volume 60, page 22461, of the *Federal Register* (60 FR 22461), the amended 10 CFR Part 54 establishes a regulatory process that is simpler, more stable, and more predictable than the previous 10 CFR Part 54. In particular, as amended, 10 CFR Part 54 focuses on the management of adverse aging effects rather than on the identification of age-related degradation unique to license renewal. The staff made these rule changes to ensure that important systems, structures, and components (SSCs) will continue to perform their intended functions during the period of extended operation. In addition, the amended 10 CFR Part 54 clarifies and simplifies the integrated plant assessment process to be consistent with the revised focus on passive, long-lived structures and components (SCs).

Concurrent with these initiatives, the staff pursued a separate rulemaking effort (Volume 61, page 28467, of the *Federal Register* (61 FR 28467), dated June 5, 1996) and amended 10 CFR Part 51 to focus the scope of the review of environmental impacts of license renewal in order to fulfill NRC 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 bases of all currently operating plants maintain an acceptable level of safety, with the possible exception of the detrimental aging effects on the function of certain SSCs, as well as a few other safety-related issues, during the period of extended operation.

(2) 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 SSCs: (1) that are safety-related, (2) whose failure could affect safety-related functions, or (3) that are relied on to demonstrate compliance with NRC regulations for fire protection, environmental qualification (EQ), pressurized thermal shock (PTS), anticipated transient without scram (ATWS), and station blackout (SBO).

Pursuant to 10 CFR 54.21(a), a license renewal applicant must review all SSCs within the scope of 10 CFR Part 54 to identify SCs subject to an aging management review (AMR). Those SCs subject to an AMR are those which perform an intended function without moving parts or without a change in configuration or properties (i.e., are “passive”), and are not subject to replacement based on a qualified life or specified time period (i.e., are “long lived”). As required by 10 CFR 54.21(a), an applicant for a renewed license must demonstrate that aging effects will be managed in such a way that the intended function(s) of those SSCs will be maintained, consistent with the current licensing basis (CLB), for the period of extended operation; however, active equipment is considered adequately monitored and maintained by existing programs. In other words, detrimental aging effects that may affect active equipment are readily detectable and can be identified and corrected through routine surveillance, performance monitoring, and maintenance. Surveillance and maintenance programs for active equipment, as well as other maintenance aspects of plant design and licensing basis, are required throughout the period of extended operation.

Pursuant to 10 CFR 54.21(d), each LRA is required to include a UFSAR supplement that must have a summary description of the applicant's programs and activities for managing aging effects and the evaluation of time-limited aging analyses (TLAAs) for the period of extended operation.

License renewal also requires TLAA identification and updating. During the plant design phase, certain assumptions are made about the length of time the plant can operate. These assumptions are incorporated into design calculations for several plant SSCs. In accordance with 10 CFR 54.21(c)(1), the applicant must show that these calculations will remain valid for the period of extended operation, project the analyses to the end of the period of extended operation, or demonstrate that effects of aging on these SSCs can be adequately managed for the period of extended operation.

In 2005, the staff developed and issued Regulatory Guide (RG) 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses." This RG endorses Nuclear Energy Institute (NEI) 95-10, Revision 6, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," issued in June 2005 by the NEI. NEI 95-10 details an acceptable method of implementing the Rule. The staff also used the SRP-LR to review this application.

In its LRA, the applicant stated that it used the process defined in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," issued in July 2001 and subsequently revised in September 2005 and December 2010. The GALL Report provides a summary of staff-approved aging management programs (AMPs) for the aging of many SCs subject to an AMR. An applicant's willingness to commit to implementing these staff-approved AMPs could potentially reduce the time, effort, and resources in reviewing an applicant's LRA, and thereby, improve the efficiency and effectiveness of the license renewal review process. The GALL Report summarizes the aging management evaluations, programs, and activities credited for managing aging for most SCs used throughout the industry. The report is also a reference for both applicants and staff reviewers to quickly identify AMPs and activities that can provide adequate aging management during the period of extended operation.

1.2.2 Environmental Review

In December 1996, the staff revised the environmental protection regulations to facilitate the environmental review for license renewal. The staff prepared the GEIS 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 applicable to all nuclear power plants. These generic findings are codified in Appendix B to Subpart A of 10 CFR Part 51. Pursuant to 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in its environmental report. In accordance with 10 CFR 51.53(c)(3)(ii), an environmental report must also include analyses of environmental impacts that must be evaluated on a plant-specific basis (i.e., Category 2 issues).

In accordance with NEPA and the requirements of 10 CFR Part 51, the staff performed a plant-specific review of the environmental impacts of license renewal, including whether the

GEIS had not considered new and significant information. As part of its scoping process, the staff held two public meetings on November 5, 2009, at the Salem County Emergency Services Building in Woodstown, New Jersey, to identify plant-specific environmental issues that might impact HCGS, or Salem Nuclear Generating Station, Units 1 and 2. The draft plant-specific GEIS Supplement 45, issued in October 2010, documents the results of the environmental review and includes a preliminary recommendation for the license renewal proposed action. Two public meetings were held on November 17, 2010, in Woodstown, New Jersey, to discuss the draft plant-specific GEIS Supplement 45. After considering comments on the draft, the staff published a final plant-specific GEIS supplement in March 2011.

1.3 Principal Review Matters

Part 54 of 10 CFR describes the requirements for renewing operating licenses for nuclear power plants. The staff performed its technical review of the LRA in accordance with NRC guidance and 10 CFR Part 54 requirements. Section 54.29 of 10 CFR sets forth the standards for renewing a license. This SER describes the results of the staff's safety review.

In accordance with 10 CFR 54.19(a), the NRC requires a license renewal applicant to submit general information. The applicant provided this general information in LRA Section 1, which it submitted, by letter dated August 18, 2009. The staff reviewed LRA Section 1 and found that the applicant had submitted the information required by 10 CFR 54.19(a).

In accordance with 10 CFR 54.19(b), the staff requires that each LRA 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 LRA Section 1.1.10 on this issue:

> 10 CFR 54.19(b) requires that "each application must 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 current indemnity agreement (No. BX08-05) for Hope Creek states in Article VII that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the Attachment to the agreement, which is the last to expire; provided that, except as may otherwise be provided in applicable regulations or orders of the Commission, the term of this agreement shall not terminate until all the radioactive material has been removed from the location and transportation of the radioactive material from the location has ended as defined in subparagraph 5(b), Article I. Item 3 of the Attachment to the indemnity agreement includes license number NPR-57. Applicant requests that any necessary conforming changes be made to Article VII and Item 3 of the Attachment, and any other sections of the indemnity agreement as appropriate to ensure that the indemnity agreement continues to apply during both the terms of the current license and the terms of the renewed license. Applicant understands that no changes may be necessary for this purpose if the current license number is retained.

The staff intends to maintain the original license number upon issuance of the renewed license, if approved. Therefore, conforming changes to the indemnity agreement need not be made and the 10 CFR 54.19(b) requirements have been met. Pursuant to 10 CFR 54.21, the staff requires that each LRA contain:

(a) an integrated plant assessment (IPA)
(b) a description of any CLB changes during the staff's review of the LRA
(c) an evaluation of TLAAs
(d) a UFSAR supplement

LRA Sections 3 and 4 and Appendix B address the license renewal requirements of 10 CFR 54.21(a), (b), and (c). LRA Appendix A satisfies the license renewal requirements of 10 CFR 54.21(d).

In accordance with 10 CFR 54.21(b), the staff requires that each year following submission of the LRA, and at least 3 months before the scheduled completion of the staff's review, the applicant submit an LRA amendment identifying any CLB changes of the facility that materially affect the contents of the LRA, including the UFSAR supplement. The applicant fulfilled this requirement by a letter dated June 24, 2010 (Agencywide Document Access Management System (ADAMS) Accession No. ML101810073).

In accordance with 10 CFR 54.22, the staff requires that an applicant's LRA include changes or additions to the technical specifications necessary to manage aging effects during the period of extended operation. In LRA Section 1, the applicant stated the following:

> There were no Technical Specification Changes identified necessary to manage the effects of aging during the period of extended operation.

The staff evaluated the technical information required by 10 CFR 54.21 and 10 CFR 54.22 in accordance with NRC regulations and the guidance of the SRP-LR. SER Sections 2, 3, and 4 document the staff's evaluation of the technical information in the LRA.

As required by 10 CFR 54.25, the ACRS will issue a report to document its evaluation of the staff's LRA review and associated SER. SER Section 5 will incorporate the ACRS report once it is issued. SER Section 6 will document the findings required by 10 CFR 54.29.

1.4 Interim Staff Guidance

License renewal is a living program. The staff, industry, and other interested stakeholders gain experience and develop lessons learned with each renewed license. The lessons learned address the NRC's safety goal of ensuring adequate protection of public health and safety and the environment. Interim staff guidance (ISG) is documented for use by the staff, industry, and other interested stakeholders until incorporated into such license renewal guidance documents as the SRP-LR and the GALL Report.

Table 1.4-1 shows the current set of approved ISGs, as well as the SER sections in which they are addressed.

Table 1.4-1 Current Interim Staff Guidance

ISG Issue (Approved ISG No.)	Purpose	SER Section
LR-ISG-2006-01	Plant-Specific Aging Management Program for Inaccessible Areas of Boiling Water Reactor Mark I Steel Containment Drywell Shell	3.0.3.2.14 and 3.5.2.2.1
LR-ISG-2007-02	Changes to Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements”	3.0.3.2.18
LR-ISG-2009-01	Aging Management of Spent Fuel Pool Neutron-Absorbing Materials other than Boraflex	3.0.3.3.5

1.5 Summary of the Open Item

As a result of its review of the LRA, including additional information submitted through May 19, 2011, the staff closed the one open item (OI), previously identified in the “Safety Evaluation Report with Open Items Related to the License Renewal of Hope Creek Generating Station” (ADAMS Accession No. ML102660148). This SER also reflects the closure of additional issues that arose since the issuance of the SER with OIs.

During a refueling outage in October 2010, the applicant observed leakage in the drywell shell and found that the four air gap drains at the bottom of the drywell were blocked. Subsequent inspections by the applicant further discovered that the actual configuration of the air gap drains were unknown. This led the staff to issue a request for additional information (RAI) concerning the leakage and the applicant’s plans for resolving and repairing the blockage and leakage. The applicant addressed the staff’s concern as discussed in Section 3.0.3.2.14 of this SER. A license condition will also be issued for the applicant to establish drainage capability from the bottom of the drywell air gap.

The staff also requested additional clarifications from the applicant regarding several programs. In response, HCGS provided additional information regarding the sampling sizes for the Selective Leaching of Materials, One-Time Inspection, and Small-Bore Class 1 Piping Inspection programs. The staff’s evaluations are documented in SER Sections 3.0.3.1.12, 3.0.3.1.11, and 3.0.3.3.6, respectively.

OI 3.0.3.2.12-1: (SER Section 3.0.3.2.12 - Buried Piping and Tanks Inspection Program)

LRA Section B.2.1.24 describes the existing Buried Piping Inspection Program as consistent, with an enhancement, with GALL AMP XI.M34, “Buried Piping and Tanks Inspection.” The applicant stated that the program provides aging management of carbon steel, ductile cast iron, and gray cast iron buried piping susceptible to general corrosion, pitting, crevice corrosion, and microbiologically-influenced corrosion. The applicant also stated that the program relies on the visual inspection of excavated piping, including the associated coatings and wrappings. The applicant further stated that there are no buried tanks within the scope of license renewal. LRA Section B.2.2.4 describes the existing Buried Non-Steel Piping Inspection Program as a plant-specific program. The applicant stated that the Buried Non-Steel Piping Inspection Program is a condition monitoring program used to manage buried reinforced concrete piping and components in its service water system for cracking, loss of bond, increase in porosity and permeability, and loss of material. The Buried Non-Steel Piping Inspection Program also manages buried stainless steel piping and components in the condensate storage and transfer system and fire protection systems for loss of material.

Given recent industry events involving leakage from buried or underground piping, the staff asked the applicant, by letter dated October 12, 2010, to address industry and plant-specific operating experience in its Buried Piping Inspection Program. In its October 29, 2010, response, the applicant provided the additional information to address the staff's concern. The staff reviewed and accepted the applicant's response, as documented in SER Sections 3.0.3.2.12 and 3.0.3.3.4. Open item OI 3.0.3.2.12-1 is closed.

1.6 Summary of Confirmatory Items

As a result of its review of the LRA, including additional information submitted through May 19, 2011, the staff closed two items that were previously confirmatory items (CIs) identified in the "Safety Evaluation Report with Open Items Related to the License Renewal of Hope Creek Generating Station" (ADAMS Accession No. ML102660148). An item is considered confirmatory if the staff and the applicant have reached a satisfactory resolution but the applicant has not yet formally submitted the resolution.

CI 3.0.3.1.20-1: (SER Section 3.0.3.1.20 - Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements)

LRA Section B.2.1.37 describes the new Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as consistent with GALL AMP XI.E3, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The applicant stated that its program manages inaccessible medium voltage cables that are exposed to significant moisture simultaneously with significant voltage. The applicant stated that significant moisture is defined as periodic exposure to moisture that lasts more than a few days (e.g., cable in standing water). The applicant also stated that significant voltage exposure is defined as being subject to system voltage for more than 25 percent of the time.

During its review, the staff noted that recently identified industry operating experience has shown that the presence of water or moisture can be a contributing factor in inaccessible power cable failures at lower service voltages (480 volts (V) to 2 kilovolts (kV)). The applicant provided a commitment to expand the scope of the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program to include cables at lower service voltages (480 V to 2 kV) and to eliminate the exclusion of cables not subject to system voltage for more than 25 percent of the time. In its responses dated September 7, 2010, and September 30, 2010, the applicant revised its Commitment No. 37 to expand the scope of this program to include cables at lower service voltages (480 V to 2 kV), to eliminate the exclusion of cables not subject to system voltage for more than 25 percent of the time and to conduct cable testing at least every 6 years and cable vault and manhole inspections at least every year. The staff reviewed and accepted the applicant's response, as documented in SER Section 3.0.3.1.20. Confirmatory item CI 3.0.3.1.20-1 is closed.

<u>CI 4.3.5.2-1</u>: (SER Section 4.3.5 - Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping (Generic Safety Issue 190))

LRA Section 4.3.5 summarizes the evaluation of the environmentally-assisted fatigue (EAF) analyses for the period of extended operation. This TLAA is based on the analysis in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The applicant stated that the effects of the reactor coolant system environment on fatigue life were evaluated for certain representative components that are identified in NUREG/CR-6260 for newer vintage General Electric plants.

As part of its analysis, the applicant identified plant-specific limiting locations per NUREG/CR-6260 and performed EAF calculations using guidance in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Curves of Carbon and Low Alloy Steels," for components made of carbon and low alloy steels and the guidance of NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," for components made of austenitic stainless steel. The applicant dispositioned its TLAA for EAF analyses based on the criterion in 10 CFR 54.21(c)(1)(iii), with the intention to demonstrate that the effects of aging associated with the analysis will be adequately managed for the period of extended operation.

During its review, the staff was concerned whether the applicant had verified that the limiting location per NUREG/CR-6260 were bounding as compared to other plant-specific locations (e.g., Feedwater Line No. AE-036, node 200/130) and requested confirmation from the applicant.

By letter dated January 6, 2011, the applicant responded to Confirmatory item CI 4.3.5.2-1 to provide Commitment No. 54 and to address the staff's concern. The staff reviewed and accepted the applicant's response because the applicant will review its design-basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 based locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for its plant configuration. If more limiting locations are identified, the applicant will perform EAF analyses for the most limiting location. Also, Commitment No. 54 is consistent with the recommendations in SRP-LR Sections 4.3.2.2 and 4.3.3.2 and GALL AMP X.M1. Additional information is documented in SER Section 4.3.5. Confirmatory item CI 4.3.5.2-1 is closed.

1.7 <u>Summary of Proposed License Conditions</u>

Following the staff's review of the LRA, including subsequent information and clarifications provided by the applicant, the staff identified four proposed license conditions.

The first license condition requires the applicant to incorporate the UFSAR supplement required by 10 CFR 54.21(d) into the UFSAR following the issuance of the renewed license.

The second license condition requires the applicant to complete the commitments in the UFSAR supplement and notify the NRC in writing when implementation of those activities required prior to the period of extended operation are complete and can be verified by NRC inspection.

The third license condition requires the applicant to establish drainage capability from the bottom of the drywell air gap from all four quadrants. Until drainage is established, the applicant will perform boroscope examinations and ultrasonic thickness measurements during each refueling outage. The applicant will monitor penetration sleeve J13 daily for water leakage when the reactor cavity is flooded and will submit a report to the staff summarizing the results from the boroscope examinations, ultrasonic thickness measurements, and leakage detected from the penetration.

The fourth license condition requires the applicant to submit a report when drainage has been established from the bottom of the air gap in all four quadrants. The applicant will also perform ultrasonic thickness measurements during the next three refueling outages and submit a report to the staff summarizing the results from the ultrasonic thickness measurements.

SECTION 2

STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

2.1 Scoping and Screening Methodology

2.1.1 Introduction

Title 10, Section 54.21, “Contents of Application—Technical Information,” of the *Code of Federal Regulations* (10 CFR 54.21), requires that each license renewal application (LRA) must contain an integrated plant assessment (IPA). The IPA must list and identify all of the structures, systems, and components (SSCs) within the scope of license renewal and all structures and components (SCs) subject to an aging management review (AMR), in accordance with 10 CFR 54.4.

LRA Section 2.1, “Scoping and Screening Methodology,” describes the scoping and screening methodology used to identify the SSCs at the Hope Creek Generating Station (HCGS), that are within the scope of license renewal and the SCs that are subject to an AMR. The staff reviewed the scoping and screening methodology applied by PSEG Nuclear, LLC (the applicant) to determine whether it meets the scoping requirements of 10 CFR 54.4(a) and the screening requirements of 10 CFR 54.21.

In developing the scoping and screening methodology for the LRA, the applicant stated that it considered the requirements of 10 CFR Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants” (the Rule), statements of consideration related to Nuclear Energy Institute (NEI) 95-10, Revision 6, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule,” (NEI 95-10). Additionally, in developing this LRA methodology, the applicant stated that it considered the correspondence between the U.S. Nuclear Regulatory Commission (NRC), other applicants, and the NEI.

2.1.2 Information Sources Used for Scoping and Screening

In LRA Section 2, “Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results,” and LRA Section 3, “Aging Management Review Results,” the applicant provides the technical information required by 10 CFR 54.4, “Scope,” and 10 CFR 54.21(a), “An Integrated Plant Assessment.” In LRA Section 2.1, the applicant described the process used to identify the SSCs that meet the license renewal scoping criteria as required by 10 CFR 54.4(a), and the process used to identify the SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1). The applicant provided the results of the process used for identifying the SCs subject to an AMR in the following LRA sections:

(a) LRA Section 2.2, “Plant Level Scoping Results”

(b) LRA Section 2.3, “Scoping and Screening Results: Mechanical”

(c) LRA Section 2.4, “Scoping and Screening Results: Structures”

(d) LRA Section 2.5, “Scoping and Screening Results: Electrical and Instrumentation and Controls (I&C) Systems”

In LRA Section 3.0, “Aging Management Review Results,” the applicant described its aging management results as follows:

(a) LRA Section 3.1, “Aging Management of Reactor Vessels, Internals, and Reactor Coolant System”

(b) LRA Section 3.2, “Aging Management of Engineered Safety Features”

(c) LRA Section 3.3, “Aging Management of Auxiliary Systems”

(d) LRA Section 3.4, “Aging Management of the Steam and Power Conversion System”

(e) LRA Section 3.5, “Aging Management of Containment, Structures and Component Supports”

(f) LRA Section 3.6, “Aging Management of Electrical and Instrumentation and Controls”

In LRA Section 4.0, “Time-Limited Aging Analyses,” the applicant identified and described the evaluation of time-limited aging analyses (TLAAs).

2.1.3 Scoping and Screening Program Review

The staff evaluated the LRA scoping and screening methodology in accordance with the guidance contained in NUREG-1800, Revision 1, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR), Section 2.1, “Scoping and Screening Methodology.” The following regulations form the basis for the acceptance criteria for the scoping and screening methodology review:

- 10 CFR 54.4(a), as it relates to the identification of plant SSCs within the scope of the Rule
- 10 CFR 54.4(b), as it relates to the identification of the intended functions of SSCs within the scope of the Rule
- 10 CFR 54.21(a)(1) and (a)(2), as they relate to the methods used by the applicant to identify plant SCs subject to an AMR

As part of the review of the applicant’s scoping and screening methodology, the staff reviewed the activities described in the following sections of the LRA using the guidance contained in the SRP-LR:

- Section 2.1, to ensure that the applicant described a process for identifying SSCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)

- Section 2.2, to ensure that the applicant described a process for determining the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) and (a)(2)

In addition, the staff conducted a scoping and screening methodology audit at HCGS, located at the southern end of Artificial Island in Lower Alloways Creek Township, Salem County, New Jersey, during the week of January 11–20, 2010. The audit focused on ensuring 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. The staff reviewed implementation of the project procedures and technical basis documents describing the applicant's scoping and screening methodology. The staff conducted detailed discussions with the applicant on the implementation and control of the license renewal program and reviewed the administrative control documentation used by the applicant during the scoping and screening process, the quality practices used by the applicant to develop the LRA, and the training and qualification of the LRA development team.

The staff evaluated the quality attributes of the applicant's aging management program (AMP) activities described in LRA Appendix A, "Final Safety Analysis Report Supplement," and Appendix B, "Aging Management Programs."

The staff selected the following systems for its review: the makeup demineralizer system, the radwaste system, the service water system, and the turbine building. For these systems, the staff reviewed the applicant's scoping and screening process, including a review of the scoping and screening results reports and the supporting design documentation used to develop the reports. The purpose of the review was to verify that the applicant had appropriately implemented the methodology outlined in the administrative controls and that the scoping and screening results are consistent with the current licensing basis (CLB) documentation.

2.1.3.1 Implementing Procedures and Documentation Sources Used for Scoping and Screening

The staff reviewed the applicant's scoping and screening implementing procedures as documented in the scoping and screening methodology audit trip report, dated August 19, 2010 (Agencywide Document Access and Management System (ADAMS) Accession No. ML102100544), to verify that the process used to identify SCs subject to an AMR was consistent with the SRP-LR. Additionally, the staff reviewed the CLB documentation sources scope and the process used by the applicant to ensure that applicant's commitments, as documented in the CLB and relative to the requirements of 10 CFR 54.4 and 10 CFR 54.21, were appropriately considered and that the applicant adequately implemented its procedural guidance during the scoping and screening process.

2.1.3.1.1 Summary of Technical Information in the Application

In LRA Section 2.1, the applicant addressed the following information references for the license renewal scoping and screening process:

- updated final safety analysis report (UFSAR)
- fire hazards analysis report
- environmental qualification master list
- maintenance rule database

- configuration baseline documents
- controlled plant component database
- engineering drawings
- engineering evaluations and calculations
- licensing correspondence

The applicant stated that it used this information to identify the functions performed by each applicable plant system and structure. It then compared these functions to the scoping criteria in 10 CFR 54.4(a) (1–3) to determine if the associated plant system or structure performed a license renewal intended function. These information sources were also used to develop the list of SCs subject to an AMR.

2.1.3.1.2 Staff Evaluation

Scoping and Screening Implementation Procedures. The staff reviewed the applicant's scoping and screening methodology implementing procedures, including license renewal guidelines, documents, and reports, as documented in the audit report, to ensure that the guidance is consistent with the requirements of the Rule, the SRP-LR, and NEI 95-10. The staff finds that the overall process used to implement the 10 CFR Part 54 requirements described in the implementing procedures and AMRs is consistent with the Rule, the SRP-LR, and NEI 95-10.

The applicant's implementing documents contain guidance for determining plant SSCs within the scope of the Rule, and for determining which SCs within the scope of license renewal are subject to an AMR. During the review of the implementing documents, the staff focused on the consistency of the detailed procedural guidance with information in the LRA, including the applicant's implementation of the staff's position concerning the SSCs that meet the 10 CFR 54.4(a) criteria, as documented in the SRP-LR.

After reviewing the LRA and its supporting documentation, the staff determined that the scoping and screening methodology implementing procedures are consistent with the methodology described in LRA Section 2.1. The applicant's methodology provides concise guidance on the scoping and screening implementation process to be followed during the implementation of the LRA.

Sources of Current Licensing Basis Information. The staff reviewed the scope and depth of the applicant's CLB review to verify that the methodology is sufficiently comprehensive to identify SSCs within the scope of license renewal, as well as any SCs requiring an AMR. Pursuant to 10 CFR 54.3(a), the CLB is the set of NRC requirements applicable to a specific plant and a licensee's written commitments for ensuring compliance with, and operation within, applicable NRC requirements and the plant-specific design bases that are docketed and in effect. The CLB includes applicable NRC regulations, orders, license conditions, exemptions, technical specifications, and design-basis information (documented in the most recent UFSAR). The CLB also includes licensee commitments remaining in effect that were made in docketed licensing correspondence, such as licensee responses to NRC bulletins, generic letters, and enforcement actions, and licensee commitments documented in NRC safety evaluations or licensee event reports.

During the audit, the staff reviewed pertinent information sources used by the applicant including the UFSAR, design-basis information, and license renewal boundary drawings. In addition, the applicant's license renewal process identified additional sources of plant information pertinent to the scoping and screening process, including the fire hazards analysis report, the environmental qualification master list, the maintenance rule database, the configurations baseline documents, controlled plant component database, engineering drawings, engineering evaluations and calculations, and licensing correspondence. The staff confirmed that the applicant's detailed license renewal program guidelines specified the use of the CLB source information in performance of the scoping and screening evaluations.

The plant component database, UFSAR, quality classifications, and design-basis information were the applicant's primary repository for system identification and component safety classification information used during performance of the scoping and screening evaluations. During the audit, the staff reviewed the applicant's administrative controls for the plant component database, design-basis information, and other information sources used to verify system information. These controls are described in and implemented by plant administrative procedures. Based on a review of the administrative controls, and a sample of the system classification information contained in the applicable HCGS documentation, the staff concludes that the applicant has established adequate measures to control the integrity and reliability of HCGS system identification and safety classification data. Therefore, the staff concludes that the information sources used by HCGS during the scoping and screening process provided a sufficiently controlled source of system and component data to support scoping and screening evaluations.

During the staff's review of the applicant's CLB evaluation process, the applicant discussed the incorporation of updates to the CLB and the process used to ensure that those updates are appropriately incorporated into the license renewal process. The staff determined that LRA Section 2.1 provided a description of the CLB and related documents used during the scoping and screening process that is consistent with the guidance contained in the SRP-LR.

The staff also reviewed the implementing procedures and the applicant's scoping and screening results reports used to support the identification of SSCs relied on to demonstrate compliance with the safety-related criteria, nonsafety-related criteria, and the regulated events criteria pursuant to 10 CFR 54.4(a). The applicant's license renewal program guidelines provided a listing of documents used to support the scoping and screening evaluations. The staff finds these design documentation sources to be useful in ensuring that the initial scope of SSCs identified by the applicant was consistent with the plant's CLB.

2.1.3.1.3 Conclusion

Based on its review of LRA Section 2.1, the detailed scoping and screening implementing procedures, and the results from the scoping and screening audit, the staff concludes that the applicant's scoping and screening methodology considers the CLB information in a manner consistent with the Rule, the SRP-LR, and NEI 95-10 guidance and, therefore, is acceptable.

2.1.3.2 Quality Controls Applied to LRA Development

2.1.3.2.1 Staff Evaluation

The staff reviewed the quality assurance controls used by the applicant to ensure that scoping and screening methodologies used in the LRA were adequately implemented. The applicant applied the following quality assurance processes during the LRA development:

- Written procedures were developed to govern the implementation of the scoping and screening methodology.
- Scoping and screening summary reports and revisions were prepared, independently verified, and approved.
- Process and procedure self-assessment was performed.
- Scoping and screening self-assessment was performed.
- The license renewal project team performed a self-assessment.
- The LRA was reviewed by the applicant's Challenge Board, the Plant Operations Review Committee, and the Nuclear Safety Review Board.
- The LRA was benchmarked relative to recent applications.
- License renewal management and staff participated in NEI license renewal activities.
- License renewal management and staff participated in external industry reviews.

The staff reviewed the applicant's written procedures and documentation of assessment activities and determined that the applicant had developed adequate procedures to provide quality control for the LRA development and assess the results of the scoping and screening activities.

2.1.3.2.2 Conclusion

On the basis of its review of the pertinent LRA development guidance, discussion with the applicant's license renewal staff, and a review of the applicant's documentation of the activities performed to assess the quality of the LRA, the staff concludes that the applicant's quality assurance activities meet the current regulatory requirements and provide assurance that LRA development activities were performed in accordance with the applicant's license renewal program requirements.

2.1.3.3 Training

2.1.3.3.1 Staff Evaluation

The staff reviewed the applicant's training process to ensure that the guidelines and methodology for the scoping and screening activities were applied in a consistent and appropriate manner. As outlined in the project procedures, the applicant requires training for all personnel participating in the development of the LRA and uses only trained and qualified personnel to prepare the scoping and screening implementing procedures. The training included the following activities:

- License renewal staff received an initial qualification which consisted of training on the following topics:
    - License renewal process overview
    - License renewal project training and reference materials
    - Relevant industry documents
- License renewal staff received additional classroom training on the following topics:
    - Site document overview
    - Systems and structures overview
    - System specific training
    - Database training
- License renewal process overview training was conducted at department staff meetings.

The staff reviewed the applicant's written procedures and reviewed some completed qualification and training records for the applicant's license renewal personnel. The staff determined that the applicant had developed and implemented adequate procedures to control the training of personnel performing LRA activities.

2.1.3.3.2 Conclusion

On the basis of discussions with the applicant's license renewal project personnel responsible for the scoping and screening process, and the staff's review of selected documentation in support of the process, the staff concludes that the applicant's personnel are adequately trained to implement the scoping and screening methodology as described in the applicant's project procedures and the LRA.

2.1.3.4 Scoping and Screening Program Review Conclusion

On the basis of a review of information provided in LRA Section 2.1, a review of the applicant's detailed scoping and screening project procedures, discussions with the applicant's license renewal personnel, and the results from the scoping and screening methodology audit, the staff concludes that the applicant's scoping and screening program is consistent with the SRP-LR and the requirements of 10 CFR Part 54 and, therefore, is acceptable.

2.1.4 Plant Systems, Structures, and Components Scoping Methodology

LRA Section 2.1 describes the applicant's methodology used to scope SSCs pursuant to the requirements of the 10 CFR 54.4(a) criteria. The LRA states that the scoping process categorized the plant in terms of major systems and structures with respect to license renewal. According to the LRA, major systems and structures were evaluated against criteria provided in 10 CFR Part 54.4(a)(1–3) to determine whether the item should be considered within the scope of license renewal. The LRA states that the scoping process identified the SSCs that: (1) are safety-related and perform or support an intended function for responding to a design-basis event (DBE); (2) are nonsafety-related but their failure could prevent accomplishment of a safety-related function; or (3) support a specific requirement for one of the five regulated events applicable to license renewal. LRA Section 2.0, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results," stated that the scoping methodology used by HCGS is consistent with the industry guidance contained in NEI 95-10, Revision 6.

2.1.4.1 Application of the Scoping Criteria in 10 CFR 54.4(a)(1)

LRA Section 2.1.3.2, "Identification of Safety-Related Systems and Structures," describes the applicant's process for scoping safety-related systems and structures to be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) scoping criterion. The process began with the HCGS plant components that have been classified as safety-related and identified as "Q" in the controlled quality classification data field in the Systems, Applications and Products in Data Processing (SAP) database. HCGS quality classification procedures were reviewed against the license renewal "safety-related" scoping criterion in 10 CFR 54.4(a)(1) to confirm that HCGS safety-related classifications are consistent with license renewal requirements.

The HCGS quality classification procedure definition of safety-related is as follows:

All safety-related structures, systems, and components required to assure:

- integrity of reactor coolant boundary
- capability to shut down the reactor and maintain it in a safe shutdown condition
- capability to prevent or mitigate the consequences of an accident which could result in potential offsite exposure comparable to the guidelines of 10 CFR Part 100
- retaining of fuel temperature within design limits by maintaining fuel coolant inventory and temperature within design limits
- control of the concentration of combustible gases in the containment system within established limits

This definition is technically equivalent to 10 CFR 54.4(a)(1) for the purposes of license renewal scoping. The wording differences are addressed as follows:

Design Basis. The HCGS procedure definition does not specifically refer to DBEs, while 10 CFR 54.4(a)(1) refers to DBEs as defined in 10 CFR 50.49(b)(1). For the HCGS license renewal, an additional technical basis document was prepared to confirm that all applicable DBEs were considered. This includes confirming that design-basis internal and external events including design-basis accidents (DBAs), anticipated operational occurrences, and natural phenomena as described in the CLB are considered when scoping for license renewal.

Exposure Limits. The HCGS quality classification procedure definition of safety-related refers to 10 CFR 100 for accident exposure limits. The license renewal rule refers to 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, as applicable. These different exposure limit requirements appear in three different Code sections to address similar accident analyses performed by licensees for different reasons. The exposure limit requirements in 10 CFR 50.34(a)(1) is not applicable to HCGS license renewal. The UFSAR refers to both 10 CFR 50.67 and 10 CFR 100 for accident exposure limits. HCGS alternate radiological source term methodology was applied (in accordance with Regulatory Guide (RG) 1.183) to the DBA analyses and, therefore, uses 10 CFR 50.67 dose acceptance criteria. The alternate radiological source term methodology for post-accident radiological analysis of certain events allows credit for some nonsafety-related components as plate-out surfaces or holdup volumes. Nonsafety-related components credited in post-accident radiological analyses for plate-out or holdup are included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The HCGS definition of safety-related includes two additional criteria that are not included in 10 CFR 54.4(a)(1). SSCs required to meet these additional criteria are included within the scope of license renewal for 10 CFR 54.4(a)(1). Therefore, the HCGS definition of safety-related is consistent with the 10 CFR 54.4(a)(1) definition for the purposes of identifying the safety-related SSCs that are within the scope of license renewal.

2.1.4.1.1 Staff Evaluation

Pursuant to 10 CFR 54.4(a)(1), the applicant must consider all safety-related SSCs relied upon to remain functional during and following a DBE to ensure the following functions: (1) the integrity of the reactor coolant pressure boundary; (2) the capability to shut down the reactor and maintain it in a safe shutdown condition; or (3) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11.

With regard to the identification of DBEs, SRP-LR Section 2.1.3, “Review Procedures,” states:

> The set of DBEs as defined in the Rule is not limited to Chapter 15 (or equivalent) of the UFSAR. Examples of DBEs that may not be described in this chapter include external events, such as floods, storms, earthquakes, tornadoes, or hurricanes, and internal events, such as a high energy line break. Information regarding DBEs as defined in 10 CFR 50.49(b)(1) may be found in any chapter of the facility UFSAR, the Commission’s regulations, NRC orders, exemptions, or license conditions within the CLB. These sources should also be reviewed to identify SSCs relied upon to remain functional during and following DBEs (as defined in 10 CFR 50.49(b)(1)) to ensure the functions described in 10 CFR 54.4(a)(1).

During the audit, the applicant stated that it evaluated the types of events listed in NEI 95-10 (i.e., anticipated operational occurrences, DBAs, external events, and natural phenomena) that were applicable to HCGS. The staff reviewed the applicant’s basis documents which described all design-basis conditions in the CLB and addressed all events defined by 10 CFR 50.49(b)(1) and 10 CFR 54.4(a)(1). The UFSAR and basis documents discussed events such as internal and external flooding, tornados, and missiles. The staff concludes that the applicant's evaluation of DBEs is consistent with the SRP-LR.

The applicant performed scoping of SSCs for the 10 CFR 54.4(a)(1) criteria in accordance with its license renewal implementing procedures which provides guidance for the preparation, review, verification, and approval of the scoping evaluations to ensure the adequacy of the results of the scoping process. The staff reviewed the implementing procedures governing the applicant's evaluation of safety-related SSCs, and sampled the applicant's reports of the scoping results to ensure that the applicant applied the methodology in accordance with the implementing procedures. In addition, the staff discussed the methodology and results with the applicant's personnel who were responsible for these evaluations.

The staff reviewed the applicant's evaluation of the Rule and CLB definitions pertaining to 10 CFR 54.4(a)(1) and determined that the CLB definition of "safety-related" met the definition of "safety-related" specified in the Rule. The staff evaluated the applicant's use of the alternate radiological source term methodology in the DBA analyses using the 10 CFR 50.67 dose acceptance criteria and found this to be acceptable. The staff also evaluated the two additional criteria in the applicant's definition of safety-related and found them to be technically equivalent to 10 CFR 54.4(a)(1) and thus, acceptable. The staff reviewed the license renewal scoping results for the makeup demineralizer system, the radwaste system, the service water system, and the turbine building, to provide additional assurance that the applicant adequately implemented its scoping methodology with respect to 10 CFR 54.4(a)(1). The staff verified that the applicant developed the scoping results for each of the sampled systems consistently with the methodology, identified the SSCs credited for performing intended functions, and adequately described the basis for the results, as well as the intended functions. The staff also confirmed that the applicant identified and used pertinent engineering and licensing information to identify the SSCs required to be within the scope of license renewal in accordance with the 10 CFR 54.4(a)(1) criterion.

During review of the LRA and performance of the scoping and screening methodology audit, performed onsite January 11–21, 2010, the staff determined that the scoping implementing documents discuss the use of the classification "SR," listed in the component classification field in the SAP, as an initial identifier of safety-related systems. In addition, the classification "Q," listed in the component classification field in the SAP, was also used to determine whether systems identified as safety-related in the SAP would be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

The staff determined that additional information would be required to complete its review. Request for additional information (RAI) 2.1-1 was issued by letter dated April 27, 2010, in which the staff requested that the applicant provide a detailed description of the use of all component classifications in the SAP, including "SR" and "Q," that were used to identify safety-related systems to be included within the scope of license renewal or used to exclude systems from within the scope of license renewal.

The applicant responded to RAI 2.1-1 by letter dated May 24, 2010, which stated that the "Q" classification was used to identify components in accordance with the classification procedure, to indicate that the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plant and Fuel Reprocessing Plants," apply. The "Quality Assurance Requirements" classification category, described in the SAP as "safety-related QA related," is the only classification category used to designate safety-related "Q" components at HCGS, and is the only classification category used in the HCGS scoping methodology to confirm that all safety-related systems were properly identified and included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) criteria. This classification category includes safety-related components that are designated “Q” in accordance with the classification procedure, to indicate that the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plant and Fuel.” The “SR” classification only applies to components at the Salem Nuclear Generating Station. In its response, the applicant stated:

> The component classification information contained in five of the SAP classification categories is determined in accordance with the Hope Creek component classification methodology procedure HC.DE-AP.ZZ-0060(Q), Functional Classification Methodology for Component Data Module Functional Locations within SAP/R3 for Hope Creek Generating Station.

The staff reviewed the applicant’s response to RAI 2.1-1 and determined that the applicant had used information contained in the component database to identify safety-related components and the parent systems to be evaluated for inclusion within the scope of license renewal, in accordance with 10 CFR 54.4(a)(1). The applicant’s response indicated that the designations “safety-related QA related” and “Q” are defined by the HCGS component classification methodology procedure HC.DE-AP.ZZ-0060(Q), which was used to classify components meeting the safety-related criteria.

In addition, during review of the LRA and performance of the scoping and screening methodology audit, performed onsite January 11–21, 2010, the staff determined that the 10 CFR 54.4(a)(1) implementing document discusses incorrect or conservative SAP component data module (CDM) classifications. The implementing procedure provided the process and results of the applicant’s determination that certain systems do not perform safety-related functions as defined in 10 CFR 54.4(a)(1), and were, therefore, not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). RAI 2.1-1 also requested that the applicant provide a detailed description of the process used to conclude that the SAP CDM classifications were conservative or incorrect and that the systems or components do not perform safety-related functions as defined in 10 CFR 54.4(a)(1). The applicant stated in its response to RAI 2.1-1 by letter dated May 24, 2010, that as a result of the SAP component data review, some safety-related components were identified in several systems that were not identified as safety-related or identified as having safety-related intended functions in other CLB documents, such as the UFSAR and Maintenance Rule system scoping documents.

The staff reviewed the applicant’s response to RAI 2.1-1 and determined that the applicant had described the process used to evaluate systems which contained components, identified as safety-related in the SAP, that were not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The staff determined that the components were contained in systems that did not have safety-related functions, were 1E electrical components identified with mechanical systems that did not have safety-related functions and were subsequently evaluated with the 1E electrical systems, or were components incorrectly identified as safety-related in the component database. The staff’s concern described in RAI 2.1-1 is resolved.

2.1.4.1.2 Conclusion

On the basis of its review of a selection of systems, discussions with the applicant, review of the applicant’s scoping process, and the response to RAI 2.1-1, the staff concludes that the applicant’s methodology for identifying systems and structures is consistent with the SRP-LR and 10 CFR 54.4(a)(1) and, therefore, is acceptable.

2.1.4.2 Application of the Scoping Criteria in 10 CFR 54.4(a)(2)

2.1.4.2.1 Summary of Technical Information in the Application

LRA Section 2.1.3.3, "10 CFR 54.4(a)(2) Scoping Criteria," describes the applicant's scoping methodology as it relates to the nonsafety-related criteria in 10 CFR 54.4(a)(2). To identify all nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in accordance with 10 CFR 54.4(a)(1), the applicant considered the following:

(1) nonsafety-related SSCs required to support a safety-related 10 CFR 54.4(a)(1) function

(2) nonsafety-related systems connected to and providing structural support for a safety-related SSC

(3) nonsafety-related systems with a potential for spatial interaction with safety-related SSCs

<u>Functional Support for Safety-Related SSC 10 CFR 54.4(a)(1) Functions</u>. LRA Section 2.1.5.2, "Nonsafety-Related Affecting Safety-Related – 10 CFR 54.4(a)(2)," states that nonsafety-related SSCs that are required to function in support of a safety-related SSC intended function are included within the scope of license renewal in accordance with 10 CFR 54.4(a)(10). The nonsafety-related SSCs that were included within the scope of license renewal under this review, to support a safety-related SSC in performing a 10 CFR 54.4(a)(1) intended function, are identified on the license renewal boundary drawings.

<u>Connected to and Providing Structural Support for Safety-Related SSCs</u>. LRA Section 2.1.5.2 states that for nonsafety-related piping connected to safety-related piping, the nonsafety-related piping was assumed to provide structural support to the safety-related piping, unless otherwise confirmed by a review of the installation details. The applicant stated that the nonsafety-related piping was included within the scope of license renewal for 10 CFR 54.4(a)(2), from the safety-related/nonsafety-related interface, to one of the following:

(1) A seismic anchor. Only true anchors that ensure forces and moments are restrained in three orthogonal directions are credited.

(2) An anchored component (e.g., pump, heat exchanger, tank, etc.) that is designed not to impose loads on connecting piping. The anchored component is included within the scope of license renewal as it has a structural support function for the safety-related piping.

(3) A flexible connection that is considered a pipe stress analysis model end point when the flexible connection effectively decouples the piping system (i.e., does not support loads or transfer loads across it to connecting piping).

(4) A free end of nonsafety-related piping, such as a drain pipe that ends at an open floor drain.

(5) For nonsafety-related piping runs that are connected at both ends to safety-related piping, the entire run of nonsafety-related piping is included within the scope of license renewal.

(6) A branch line off of a header where the moment of inertia of the header is greater than 15 times the moment of inertia of the branch. The header is treated as an anchor.

Potential for Spatial Interactions with Safety-Related SSCs. LRA Section 2.1.5.2 states that nonsafety-related systems that are not connected to safety-related piping or components, or are beyond the first seismic anchor past the safety/nonsafety interface, and have a spatial relationship such that their failure could adversely impact the performance of a safety-related SSC intended function, must be evaluated for license renewal scope in accordance with 10 CFR 54.4(a)(2) requirements. The applicant used the preventive option described in NEI 95-10, Appendix F, to determine the scope of license renewal with respect to the protection of safety-related SSCs from spatial interactions. This scoping process, referred to as the "spaces" approach, involves an evaluation based on equipment location and the related SSCs and whether or not fluid-filled system components are located in the same space as safety-related equipment. A "space," for the purposes of the review, was defined as a structure containing active or passive safety-related SSCs.

2.1.4.2.2 Staff Evaluation

Pursuant to 10 CFR 54.4(a)(2), the applicant must consider all nonsafety-related SSCs, whose failure could prevent the satisfactory accomplishment of safety-related functions of SSCs relied on to remain functional during and following a DBE to ensure: (1) the integrity of the reactor coolant pressure boundary; (2) the capability to shut down the reactor and maintain it in a safe shutdown condition; or (3) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11.

RG 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses," Revision 1, endorses the use of NEI 95-10, Revision 6. NEI 95-10 discusses the staff's position on 10 CFR 54.4(a)(2) scoping criteria, including: (1) nonsafety-related SSCs typically identified in the CLB; (2) consideration of missiles, cranes, flooding, and high-energy line breaks (HELBs); (3) nonsafety-related SSCs connected to safety-related SSCs; (4) nonsafety-related SSCs in proximity to safety-related SSCs; and (5) mitigative and preventive options related to nonsafety-related and safety-related SSC interactions.

As discussed in NEI 95-10, Revision 6, applicants should not consider hypothetical failures but rather, should base their evaluation on the plant's CLB, engineering judgment and analyses, and relevant operating experience. NEI 95-10 further describes operating experience as all documented plant-specific and industry-wide experience that can be used to determine the plausibility of a failure. Documentation would include NRC generic communications and event reports, plant-specific condition reports, industry reports such as safety operational event reports, and engineering evaluations. The staff reviewed LRA Sections 2.1.3.3 and 2.1.5.2 in which the applicant described the scoping methodology for nonsafety-related SSCs pursuant to 10 CFR 54.4(a)(2). In addition, the staff reviewed the applicant's implementing document and results report, which documented the guidance and corresponding results of the applicant's scoping review pursuant to 10 CFR 54.4(a)(2). The applicant stated that it performed the review in accordance with the guidance contained in NEI 95-10, Revision 6, Appendix F.

Nonsafety-Related SSCs Required to Perform a Function that Supports a Safety-Related SSC. The staff determined that nonsafety-related SSCs required to remain functional to support a safety-related function had been reviewed by the applicant for inclusion within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2). The staff reviewed the evaluating criteria discussed in LRA Sections 2.1.3.3 and 2.1.5.2 and the applicant's 10 CFR 54.4(a)(2) implementing document. The staff confirmed that the applicant had reviewed the UFSAR, plant drawings, plant component database, and other CLB documents to identify the nonsafety-related systems and structures that function to support a safety-related system whose failure could prevent the performance of a safety-related function. The applicant also considered missiles, overhead handling systems, internal and external flooding, and HELBs. Accordingly, the staff finds that the applicant implemented an acceptable method for including nonsafety-related systems that perform functions that support safety-related intended functions within the scope of license renewal, as required by 10 CFR 54.4(a)(2).

Nonsafety-Related SSCs Directly Connected to Safety-Related SSCs. The staff confirmed that nonsafety-related SSCs, directly connected to SSCs, had been reviewed by the applicant for inclusion within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2). The staff reviewed the evaluating criteria discussed in the LRA and the applicant's 10 CFR 54.4(a)(2) implementing document. Based on its review, the staff determined that the applicant had reviewed the safety-related to nonsafety-related interfaces for each mechanical system in order to identify the nonsafety-related components located between the safety-related to nonsafety-related interface and license renewal structural boundary.

The staff determined that in order to identify the nonsafety-related SSCs connected to safety-related SSCs and for the nonsafety-related SSCs to be structurally sound to maintain the integrity of the safety-related SSCs, as required, the applicant used a combination of the following to identify the portion of nonsafety-related piping systems to include within the scope of license renewal:

- seismic anchors
- bounding conditions described in NEI 95-10, Revision 6, Appendix F, such as base-mounted component, flexible connection, free end of nonsafety-related piping, or inclusion of the entire nonsafety-related piping run

Nonsafety-Related SSCs with the Potential for Spatial Interaction with Safety-Related SSCs. The staff confirmed that nonsafety-related SSCs with the potential for spatial interaction with safety-related SSCs had been reviewed by the applicant for inclusion within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2). The staff reviewed the evaluating criteria discussed in LRA Section 2.1.5.2 and the applicant's 10 CFR 54.4(a)(2) implementing procedure. LRA Section 2.1.5.2 and the applicant's implementing document state that the applicant had used a preventive approach, which considered the impact of nonsafety-related SSCs contained in the same space as safety-related SSCs. The staff determined that the applicant had evaluated all nonsafety-related SSCs containing liquid or steam and located in spaces containing safety-related SSCs. The applicant used a spaces approach to identify the nonsafety-related SSCs that were located within the same space as safety-related SSCs. As described in the LRA and for the purpose of the scoping review, a space was defined as a structure containing active or passive safety-related SSCs. In addition, the staff determined that following the identification of the applicable mechanical systems, the applicant identified its corresponding structures for potential spatial interaction, based on a review of the CLB and plant walkdowns. Nonsafety-related systems and components that contain liquid or steam and are located inside structures that contain safety-related SSCs were included within the scope of license renewal, unless it was in an excluded space (i.e., a space with no safety-related SSCs). The staff also determined that based on plant and industry operating experience, the applicant excluded the nonsafety-related SSCs containing air or gas from the scope of license renewal, with the exception of portions that are attached to safety-related SSCs and required for structural support. The staff confirmed that those nonsafety-related SSCs determined to contain liquid or steam and located within a space containing safety-related SSCs were included within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2).

2.1.4.2.3 Conclusion

On the basis of its review of the applicant's scoping process and discussions with the applicant, the staff concludes that the applicant's methodology for identifying and including nonsafety-related SSCs, that could affect the performance of safety-related SSCs, within the scope of license renewal, is consistent with the scoping criteria of 10 CFR 54.4(a)(2) and, therefore, is acceptable.

2.1.4.3 Application of the Scoping Criteria in 10 CFR 54.4(a)(3)

2.1.4.3.1 Summary of Technical Information in the Application

LRA Section 2.1.5.3, "Regulated Events–10 CFR 54.4(a)(3)," describes the methodology for identifying those systems and structures within the scope of license renewal in accordance with the NRC criteria for five regulated events: (1) 10 CFR 50.48, "Fire Protection"; (2) 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"; (3) 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events"; (4) 10 CFR 50.62, "Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants"; and (5) 10 CFR 50.63, "Loss of All Alternating Current Power."

<u>Fire Protection</u>. LRA Section 2.1.3.4, "Scoping for Regulated Events," subsection "Fire Protection" describes the scoping of all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for fire protection (10 CFR 50.48). The applicant stated that this scope of systems and structures included:

- systems and structures required to demonstrate post-fire safe shutdown capabilities
- systems and structures required for fire detection and suppression
- systems and structures required to meet commitments made to Appendix A of Branch Technical Position (BTP) (APCSB 9.5-1)

<u>Environmental Qualification (EQ)</u>. LRA Section 2.1.3.4, subsection "Environmental Qualification," describes the scoping of systems and structures relied on in safety analyses or plant evaluations to perform a function in compliance with the EQ criterion. The LRA states that the HCGS EQ program includes safety-related electrical equipment, nonsafety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions of the safety-related equipment, and certain post-accident

monitoring equipment, as defined in 10 CFR 50.49(b)(1), 10 CFR 50.49(b)(2), and 10 CFR 50.49(b)(3), respectively.

Pressurized Thermal Shock. LRA Section 2.1.5.3, subsection “Pressurized Thermal Shock,” states, “The regulation for pressurized thermal shock (10 CFR 50.61) is applicable to pressurized water reactors only, and is therefore not applicable [to] the HCGS boiling water reactor.”

Anticipated Transient Without Scram. LRA Section 2.1.3.4, subsection “Anticipated Transients Without Scram,” describes the scoping of systems and structures relied on in safety analyses or plant evaluations to perform a function in compliance with the ATWS criterion. The LRA states that an ATWS is a postulated operational transient that generates an automatic scram signal, accompanied by a failure of the reactor protection system to shutdown the reactor. The LRA states that:

> Hope Creek has a Redundant Reactivity Control System (RRCS) that is designed to mitigate the potential consequences of an ATWS event. The system consists of remote control panels, their associated ATWS detection and actuation logic and the necessary interface logic to the reactor recirculation system, the feed water control system, the reactor water cleanup system, the standby liquid control (SLC) system, and the alternate rod insertion (ARI) components of the control rod drive system required to perform specific functions in response to an ATWS event. Hope Creek also has an adequately sized standby liquid control system that is initiated automatically by the RRCS logic when needed.

The ATWS basis document provides a list of the systems required by 10 CFR 50.62 to reduce the risk from ATWS events. The basis document also provides a list of structures that provide physical support and protection for the ATWS systems. These systems and structures are included within the scope of license renewal under the 10 CFR 54.4(a)(3) scoping criteria.

Station Blackout. LRA Section 2.1.3.4, subsection “Station Blackout,” describes the scoping of systems and structures relied on in safety analyses or plant evaluations to perform functions in compliance with the SBO criterion. HCGS satisfies the requirement of 10 CFR 50.63 as an alternating current independent, 4-hour coping plant. The NUREG-1800 guidance on scoping of equipment relied on to meet the requirements of the station blackout (SBO) rule (10 CFR 50.63) for license renewal has been incorporated into the HCGS scoping methodology. In accordance with the NUREG-1800 requirements, the SSCs required to recover from the SBO event are included within the scope of license renewal. Recovery is defined as the repowering of the plant AC distribution system from offsite sources or onsite emergency AC sources.

2.1.4.3.2 Staff Evaluation

The staff reviewed the applicant’s approach to identifying SSCs relied upon to perform functions meeting the requirements of the fire protection, EQ, ATWS, and SBO regulations. As part of this review, the staff discussed the methodology with the applicant, reviewed the documentation developed to support the approach, and evaluated selected mechanical systems and structures included within the scope of license renewal pursuant to 10 CFR 54.4(a)(3).

Fire Protection. The staff determined that the applicant’s implementing procedures indicated that it had included systems and structures within the scope of license renewal required for post-fire safe shutdown, fire detection suppression, and commitments made to Appendix A to BTP APCSB 9.5-1, “Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to

July 1, 1976," issued May 1976. The applicant noted that it had considered CLB documents to identify systems and structures within the scope of license renewal. These documents included the 10 CFR 50, Appendix R, Fire Study and HCGS's Fire Protection Plan; fire protection systems scoping and screening basis document; Fire Hazards Analysis Report; the fire protection program plan as required by 10 CFR 50.48; UFSAR; drawings; and other HCGS technical basis documents. The staff reviewed selected scoping results in conjunction with the LRA and the CLB information to validate the methodology for including the appropriate systems and structures within the scope of license renewal. Based on its review of the CLB documents and the sample review, the staff determined that the applicant's scoping methodology was adequate for including SSCs credited in performing fire protection functions, in accordance with 10 CFR 50.48, within the scope of license renewal.

Environmental Qualification. The staff determined that the applicant's implementing procedures required the inclusion of safety-related electrical equipment, nonsafety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishments of safety functions of the safety-related equipment, and certain post-accident monitoring equipment, as defined in 10 CFR 50.49(b)(1), (b)(2), and (b)(3). The staff reviewed the LRA, implementing procedures, the EQ systems scoping and screening basis document, and the EQ master component equipment list to verify that the applicant identified SSCs within the scope of license renewal that meet the LRA EQ requirements. Based on that review, the staff determined that the applicant's scoping methodology is adequate for identifying SSCs that meet the requirements of 10 CFR 50.49 within the scope of license renewal.

Pressurized Thermal Shock. The regulation for pressurized thermal shock (10 CFR 50.61) is applicable to pressurized water reactors only and is, therefore, not applicable to the HCGS boiling-water reactor.

Anticipated Transient Without Scram. The staff determined that the applicant had generated a list of plant systems credited for ATWS mitigation based on review of the plant and the ATWS systems scoping and screening documents, the UFSAR, docketed correspondence, modifications, and the plant component database. The staff reviewed these documents and the LRA in conjunction with the scoping results to validate the methodology for identifying ATWS systems and structures that are within the scope of license renewal. The staff determined that the applicant's scoping methodology was adequate for identifying SSCs that meet the requirements of 10 CFR 50.62 and are within the scope of license renewal.

Station Blackout. The staff determined that the applicant identified those systems and structures associated with coping and safe shutdown of the plant following an SBO event by reviewing plant-specific SBO systems, scoping and screening basis document calculations, the UFSAR, drawings, modifications, the plant component database, and plant procedures. The staff reviewed (on a sampling basis) these documents and the LRA in conjunction with the scoping results to validate the applicant's methodology. The staff finds that the scoping results included systems and structures that perform intended functions meeting 10 CFR 50.63 requirements. The staff determined that the applicant's scoping methodology was adequate for identifying SSCs credited that meet the requirements of 10 CFR 50.63 within the scope of license renewal.

2.1.4.3.3 Conclusion

On the basis of the selected reviews, discussion with the applicant, review of the LRA, and review of the implementing procedures and reports, the staff concludes that the applicant's methodology for identifying systems and structures meets the scoping criteria pursuant to 10 CFR 54.4(a)(3) and, therefore, is acceptable.

2.1.4.4 Plant-Level Scoping of Systems and Structures

2.1.4.4.1 Summary of Technical Information in the Application

LRA Section 2.1, "Scoping and Screening Methodology," documents the applicant's methodology for performing the scoping of systems and structures in accordance with the requirements of 10 CFR 54.4(a) in the LRA, guidance documents, and scoping and screening reports. The initial step in the scoping process was to define the entire plant in terms of systems and structures. These systems and structures were evaluated against the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), and (a)(3), to determine if they perform or support a safety-related intended function, or perform functions that demonstrate compliance with the requirements of one of the five license renewal regulated events. For the systems and structures determined to be in-scope, the intended functions that are the bases for including the systems and structures in-scope were also identified. If any portion of a system or structure met the scoping criteria of 10 CFR 54.4, the system or structure was included within the scope of license renewal. Mechanical systems and structures were then further evaluated to determine those mechanical and structural components that perform or support the identified intended functions. All electrical components within in-scope mechanical and electrical systems were included within the scope of license renewal as electrical commodities.

LRA Section 2.1.2, "Information Sources Used for Scoping and Screening," states that the UFSAR, fire hazards analysis report, environmental qualification master list, and maintenance rule database were primary sources of information used during the scoping process.

LRA Section 2.1.6.3, "Stored Equipment," states that equipment that is stored onsite for installation in response to a DBE is considered to be within the scope of license renewal. At HCGS, certain fire scenarios use stored equipment to facilitate repairs following the fire. The stored equipment credited is listed in controlled station procedures. These components are confirmed available and in good operating condition by periodic surveillance inspections.

LRA Section 2.1.6.4, "Consumables," states that the evaluation process for consumables is consistent with the guidance provided in NUREG-1800, Table 2.1-3. Consumables have been divided into the following four categories for the purpose of license renewal: (1) packing, gaskets, component seals, and O-rings; (2) structural sealants; (3) oil, grease, and component filters; and (4) system filters, fire extinguishers, fire hoses, and airpacks.

2.1.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.1 and the applicant's methodology for performing the plant-level scoping of systems and structures to ensure it was consistent with 10 CFR 54.4. The methodology used to determine the systems and structures within the scope of license renewal was documented in implementing procedures and scoping results reports for systems. The scoping process defined the plant in terms of systems and structures. Specifically, the implementing procedures identified the systems and structures that are subject to 10 CFR 54.4 review, described the processes for capturing the results of the review, and were used to determine if the system or structure performed intended functions consistent with the criteria of 10 CFR 54.4(a). The process was completed for all systems and structures to ensure that the entire plant was addressed.

The staff reviewed the LRA Section 2.1.6.3 and applicable implementing procedures that addressed the process used to evaluate stored equipment, credited for response to a DBE, for inclusion within the scope of license renewal. The staff determined that the applicant had appropriately considered stored equipment and included it within the scope of license renewal. In addition, the staff reviewed the LRA Section 2.1.6.4 and applicable implementing procedures that addressed the process used to evaluate consumables for inclusion within the scope of license renewal. The applicant had divided consumables into the following four categories for the purpose of license renewal: (1) packing, gaskets, component seals, and O-rings; (2) structural sealants; (3) oil, grease, and component filters; and (4) system filters, fire extinguishers, fire hoses, and air packs. The staff determined that the applicant had appropriately determined the appropriate categories for consumables to be included within the scope of license renewal.

The applicant documented the results of the plant-level scoping process in accordance with the implementing procedures. The results were provided in the systems and structures documents and reports which contained information including a description of the system or structure, a listing of functions performed by the system or structure, identification of intended functions, the 10 CFR 54.4(a) scoping criteria met by the system or structure, references, and the basis for the classification of the system or structure intended functions. During the audit, the staff reviewed a sampling of the documents and reports and concluded that the applicant’s scoping results contained an appropriate level of detail to document the scoping process.

2.1.4.4.3 Conclusion

Based on its review of the LRA, implementing procedures, reports, and a sampling of system scoping results reviewed during the audit, the staff concludes that the applicant’s methodology for identifying systems and structures within the scope of license renewal, and their intended functions, is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.5 Mechanical Component Scoping

2.1.4.5.1 Summary of Technical Information in the Application

In addition to the information previously discussed in safety evaluation report (SER) Section 2.1.4.4.1, LRA Section 2.1.5, “Scoping Procedure,” describes the methodology for identifying license renewal evaluation boundaries. System and structure functions and intended functions were identified from a review of the source CLB documents. In-scope boundaries were established and documented in the scoping evaluations, based on the identified intended functions. The in-scope boundaries form the basis for identification of the in-scope components, which is the first step in the screening process. LRA Section 2.1.5.5, “Scoping Boundary Determination,” states that the mechanical components that support the system intended functions are included within the scope of license renewal and are depicted on the applicable system piping and instrumentation diagram. Mechanical system piping and instrumentation diagrams are marked up to create license renewal boundary drawings showing the in-scope components. Components that are required to support a safety-related function, or a function that demonstrates compliance with one of the license renewal regulated events, are identified on the system piping and instrumentation diagram. Nonsafety-related components that are connected to safety-related components and are required to provide structural support at the safety/nonsafety interface, or components whose failure could prevent satisfactory accomplishment of a safety-related function due to spatial interaction with safety-related SSCs, are identified on license renewal drawings. A computer sort and download of associated system components from the SAP database were used to confirm the scope of components in the system. Plant walkdowns were performed when required for additional confirmation.

2.1.4.5.2 Staff Evaluation

The staff used the SRP-LR to evaluate LRA Sections 2.1.5 and 2.1.5.5 and the guidance in the implementing procedures and reports used by the applicant to perform the review of the mechanical scoping process. The implementing procedures and reports which the applicant used provided instructions for identifying the evaluation boundaries. Information related to system operations in support of the intended functions was necessary to determine the mechanical system evaluation boundary. Based on the review of the implementing procedures and the CLB documents associated with mechanical system scoping, the staff determined that the guidance and CLB source information noted above were consistent with the information in the LRA for identifying mechanical components and support structures in mechanical systems that are within the scope of license renewal.

The staff conducted detailed discussions with the applicant's license renewal project personnel and reviewed documentation pertinent to the scoping process. The staff assessed whether the applicant had appropriately applied the scoping methodology outlined in the LRA and implementing procedures and whether the scoping results were consistent with CLB requirements. The staff determined that the applicant's procedure was consistent with the description provided in LRA Sections 2.1.5 and 2.1.5.5 and the guidance contained in SRP-LR Section 2.1, and was adequately implemented.

The staff reviewed the applicant's scoping reports for the makeup demineralizer system, the radwaste system, and the service water system for mechanical component types that met the scoping criteria of 10 CFR 54.4. The staff verified that the applicant had identified and used pertinent engineering and licensing information in order to determine the mechanical component types required to be within the scope of license renewal. As part of the review process, the staff evaluated: (1) each system's intended functions identified for the makeup demineralizer system, the radwaste system, and the service water system; (2) the basis for inclusion of the intended function; and (3) the process used to identify each of the system component types. The staff verified that the applicant had identified and highlighted system drawings to develop the license renewal boundaries in accordance with the procedural guidance. Additionally, the staff determined that the applicant had performed an independent verification of the results in accordance with the governing procedures. The staff confirmed that the applicant had license renewal personnel knowledgeable about the system and that these personnel had performed independent reviews of the highlighted drawings to ensure accurate identification of system intended functions. The staff also confirmed that the applicant had performed additional cross-discipline verification and independent reviews of the resultant highlighted drawings before final approval of the scoping effort.

2.1.4.5.3 Conclusion

On the basis of its review of the LRA, scoping implementing procedures, the sample system review, and discussions with the applicant, the staff concludes that the applicant's methodology for identifying mechanical systems within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.6 Structural Scoping

2.1.4.6.1 Summary of Technical Information in the Application

LRA Section 2.1.5 identifies the scoping process for structures as stated in the previous section. LRA Section 2.1.5.5 states that the structural components that support the intended functions are included within the scope of license renewal. The structural components were identified from a review of applicable plant design drawings of the structure and plant walkdowns.

2.1.4.6.2 Staff Evaluation

The staff evaluated LRA Sections 2.1.5 and 2.1.5.5 and subsections, and the guidance contained in the applicant's implementing procedures and reports to perform the review of the structural scoping process. The staff reviewed the applicant's approach to identifying structures relied upon to perform the functions described in 10 CFR 54.4(a). As part of this review, the staff discussed the methodology with the applicant, reviewed the documentation developed to support the review, and evaluated the scoping results for a sample of structures that were identified within the scope of license renewal. The staff determined that the applicant had identified and developed a list of plant structures and the structures' intended functions through a review of the plant component database, the Structures Monitoring Program, UFSAR, controlled drawings, maintenance procedures, and walkdowns. Each structure the applicant identified was evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

The staff reviewed selected portions of the plant component database, UFSAR, drawings, procedures, and implementing procedures to verify the adequacy of the methodology. The staff reviewed source documentation for the turbine building to verify that the application of the methodology would provide the results as documented in the turbine building scoping report and in the LRA. The staff verified that the applicant had identified and used pertinent engineering and licensing information in order to determine that the turbine building was required to be included within the scope of license renewal. In addition, during the scoping and screening methodology audit, the staff performed walkdowns of selected areas of the turbine building to verify proper implementation of the scoping process. As part of the review process, the staff evaluated the intended functions identified for the turbine building and the structural components, the basis for inclusion of the intended function, and the process used to identify each of the component types.

2.1.4.6.3 Conclusion

On the basis of its review of information in the LRA, scoping implementing procedures, and a sampling review of structural scoping results, the staff concludes that the applicant's methodology for the scoping of the structures within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.7 Electrical Component Scoping

2.1.4.7.1 Summary of Technical Information in the Application

LRA Section 2.1.5.5 describes the applicant's process for scoping electrical and instrumentation and control (I&C) systems, and electrical components in mechanical systems within the scope of license renewal. A bounding scoping approach was used for electrical equipment. All electrical components within in-scope systems were included within the scope of license renewal. In-scope electrical components were placed into commodity groups and were evaluated as commodities during the screening process.

2.1.4.7.2 Staff Evaluation

The staff evaluated LRA Sections 2.1.5 and 2.1.5.5 and subsections, and the applicant's guidance contained in the implementing procedures and reports to perform the review of the electrical scoping process. The staff reviewed the applicant's approach to identifying electrical and I&C SSCs relied upon to perform the functions described in 10 CFR 54.4(a). The staff reviewed portions of the documentation used by the applicant to perform the electrical scoping process including the UFSAR, the plant component database, CLB documentation, drawings, and specifications. As part of this review, the staff discussed the methodology with the applicant, reviewed the implementing procedures developed to support the review, and evaluated the scoping results for a sample of SSCs that were identified within the scope of license renewal. The staff determined that the applicant had included electrical and I&C components, including components contained in the mechanical or structural systems, within the scope of license renewal on a commodity basis.

2.1.4.7.3 Conclusion

On the basis of its review of information contained in the LRA, implementing procedures and supporting documents, discussions with the applicant, and a review of selected electrical scoping results, the staff concludes that the applicant's methodology for the identification of electrical and I&C SSCs within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.8 Scoping Methodology Conclusion

On the basis of its review of the LRA, implementing procedures, and a review of selected scoping results, the staff concludes that the applicant's scoping methodology was consistent with the guidance contained in the SRP-LR and identified those SSCs: (a) that are safety-related, (b) whose failure could affect safety-related functions, and (c) that are necessary to demonstrate compliance with the NRC regulations for fire protection, EQ, pressurized thermal shock, ATWS, and SBO. The staff concludes that the applicant's methodology is consistent with the requirements of 10 CFR 54.4(a) and, therefore, is acceptable.

2.1.5 Screening Methodology

2.1.5.1 General Screening Methodology

2.1.5.1.1 Summary of Technical Information in the Application

LRA Section 2.1.6.1, "Identification of Structures and Components Subject to AMR," describes the screening process that identifies the SCs within the scope of license renewal that are subject to an AMR. The screening procedure is the process used to identify the passive, long-lived SCs that are within the scope of license renewal and thus, subject to an AMR. The SRP-LR and NEI 95-10, Appendix B were used as the basis for the identification of passive SCs. Most passive SCs are long-lived. In the few cases where a passive component is determined not to be long-lived, such determination is documented in the screening evaluation and, if applicable, on the associated license renewal boundary drawing.

2.1.5.1.2 Staff Evaluation

Pursuant to 10 CFR 54.21, each LRA must contain an IPA that identifies SCs within the scope of license renewal that are subject to an AMR. The IPA must identify components that perform an intended function without moving parts or a change in configuration or properties (passive), as well as components that are not subject to periodic replacement based on a qualified life or specified time period (long-lived). In addition, the IPA must include a description and justification of the methodology used to determine the passive and long-lived SCs, and a demonstration that the effects of aging on those SCs will be adequately managed so that the intended function(s) will be maintained under all design conditions imposed by the plant-specific CLB for the period of extended operation.

The staff reviewed the methodology used by the applicant to identify the mechanical and structural components and electrical commodity groups[1] within the scope of license renewal that should be subject to an AMR. The applicant implemented a process for determining which SCs were subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). In LRA Section 2.1.6.1, the applicant discussed these screening activities as they relate to the component types and commodity groups within the scope of license renewal.

The staff determined that the applicant's screening process evaluated the component types and commodity groups, included within the scope of license renewal, to determine which ones were long-lived and passive and, therefore, subject to an AMR. The staff reviewed LRA Section 2.3, "Scoping and Screening Results: Mechanical"; LRA Section 2.4, "Scoping and Screening Results: Structures"; and LRA Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Controls (I&C) Systems." These LRA sections provide the results of the process used to identify component types and commodity groups subject to an AMR. The applicant provided the staff with a detailed discussion of the processes used for each discipline and provided administrative documentation that described the screening methodology. The staff also reviewed screening results reports for the makeup demineralizer system, the radwaste system, the service water system, and the turbine building.

2.1.5.1.3 Conclusion

On the basis of its review of the LRA, the implementing procedures, and selected screening results, the staff concludes that the applicant's screening methodology was consistent with the guidance contained in the SRP-LR and was capable of identifying passive, long-lived components within the scope of license renewal that are subject to an AMR. The staff concludes that the applicant's process for determining which component types and commodity groups subject to an AMR is in accordance with the requirements of 10 CFR 54.21 and, therefore, is acceptable.

[1] For scoping, the applicant may also group like structures and components into commodity groups. The basis for grouping structures and components can be determined by such characteristics as similar function, similar design, similar materials of construction, similar aging management practices, or similar environments. If the applicant uses commodity groups, the reviewer verifies that the applicant has described the basis for the groups.

2.1.5.2 Mechanical Component Screening

2.1.5.2.1 Summary of Technical Information in the Application

LRA Section 2.1.6.1, “Identification of Structures and Components Subject to AMR,” describes the applicant’s process for identifying mechanical components within the scope of license renewal that were subject to an AMR. For in-scope mechanical systems, the completed scoping packages include written descriptions and marked up system piping and instrumentation diagrams that clearly identify the in-scope system boundary for license renewal. The marked up system piping and instrumentation diagrams are called boundary drawings for license renewal. These system boundary drawings were carefully reviewed to identify the passive, long-lived components, and the identified components were then entered into the license renewal database. Component listings from the SAP database were also reviewed to confirm that all system components were considered. In cases where the system piping and instrumentation diagram did not provide sufficient detail, such as for some large vendor supplied components (e.g., compressors, emergency diesel generators), the associated component drawings or vendor manuals were also reviewed. Plant walkdowns were performed when required for confirmation. Finally, the identified list of passive, long-lived system components was benchmarked against previous LRAs containing a similar system.

2.1.5.2.2 Staff Evaluation

The staff reviewed the mechanical screening methodology discussed and documented in LRA Section 2.1.6.1, implementing procedures, scoping and screening reports, and license renewal drawings. The staff determined that the mechanical system screening process used the results from the scoping process and that the applicant reviewed each system evaluation boundary as depicted on system drawings to identify passive and long-lived components.

Additionally, the staff determined that the applicant had identified all passive and long- lived components that perform or support a function within the system evaluation boundaries and determined those components that are subject to an AMR. The results of the review were documented in the scoping and screening reports, which contain the information sources reviewed and the component functions.

The staff confirmed that the applicant reviewed the components within the system intended function boundary to determine if the component supported the system intended function and that those components that supported the system intended function were reviewed to determine if the component was passive and long-lived and, therefore, subject to an AMR.

The staff reviewed portions of the UFSAR, plant component database, CLB documentation, procedures, drawings, specifications, and selected scoping and screening reports. The staff conducted detailed discussions with the applicant’s license renewal team and reviewed documentation pertinent to the screening process. The staff assessed whether the mechanical screening methodology outlined in the LRA and implementing procedures was appropriately implemented and if the screening results were consistent with CLB requirements. During the scoping and screening methodology audit, the staff discussed the screening methodology with the applicant and reviewed the applicant’s screening reports for the makeup demineralizer system, the radwaste system, and the service water system, to verify proper implementation of the screening process. In addition, the staff performed walkdowns of selected portions of the systems as an example of the methodology and its implementation. Based on the review activities, the staff did not identify any discrepancies between the methodology documented and the implementation results.

2.1.5.2.3 Conclusion

On the basis of its review of the LRA, the screening implementation procedures, selected portions of the UFSAR, plant component database, CLB documentation, procedures, drawings, specifications, selected scoping and screening reports, and selected results for selected systems, the staff concludes that the applicant's methodology for identification of mechanical components subject to an AMR is in accordance with the requirements of 10 CFR 54.21(a)(1) and, therefore, is acceptable.

2.1.5.3 Structural Component Screening

2.1.5.3.1 Summary of Technical Information in the Application

LRA Section 2.1.6.1, "Identification of Structures and Components Subject to AMR," describes the applicant's process of screening structural components that are subject to an AMR. The structure drawings for in-scope structures were carefully reviewed to identify the passive, long-lived SCs, and the identified SCs were then entered into the license renewal database. Component listings from the SAP database were also reviewed to confirm that all structural components were considered. Plant walkdowns were performed when required for confirmation. Finally, the identified list of passive, long-lived SCs was benchmarked against previous LRAs.

2.1.5.3.2 Staff Evaluation

The staff reviewed the structural screening methodology discussed and documented in LRA Section 2.1.6, the implementing procedures, and the license renewal drawings. The staff reviewed the applicant's methodology for identifying structural components that are subject to an AMR, as required by 10 CFR 54.21(a)(1). The staff confirmed that the applicant had reviewed the structures included within the scope of license renewal and identified the passive, long-lived components with component-level intended functions and determined those components to be subject to an AMR.

The staff reviewed selected portions of the UFSAR, the Structures Monitoring Program, and scoping and screening reports, which the applicant used to perform the structural scoping and screening activities. The staff also reviewed, on a sampling basis, the structural drawings to document the SCs within the scope of license renewal and subject to an AMR. The staff conducted discussions with the applicant's license renewal team and reviewed documentation pertinent to the screening process to assess if the screening methodology outlined in the LRA and implementing procedures were appropriately implemented and if the screening results were consistent with the CLB requirements. In addition, during the scoping and screening methodology audit, the staff reviewed the turbine building to verify proper implementation of the screening process and performed walkdowns of selected areas. Based on the review activities, the staff did not identify any discrepancies between the methodology documented and the implementation results.

2.1.5.3.3 Conclusion

On the basis of its review of the LRA, implementation procedures, the UFSAR, CLB documentation, drawings, and selected scoping and screening reports, discussion with the applicant, and a sample of the results of the screening methodology, the staff concludes that the methodology for identification of structural components within the scope of license renewal and subject to an AMR is in accordance with the requirements of 10 CFR 54.21(a)(1) and, therefore, is acceptable.

2.1.5.4 Electrical Component Screening

2.1.5.4.1 Summary of Technical Information in the Application

LRA Section 2.1.6.1, “Identification of Structures and Components Subject to AMR,” describes the screening of electrical and I&C components. The applicant used a bounding approach as described in NEI 95-10. The sequence of steps and special considerations for the identification of electrical components that require an AMR is as follows:

(1) Electrical and I&C components within in-scope systems at HCGS were identified and listed. The electrical and I&C component commodity groups were identified from a review of plant documents, controlled drawings, the plant component database (SAP), and interface with the parallel mechanical and civil/structural screening efforts.

(2) The criterion of 10 CFR 54.21(a)(1)(i) was applied to identify component commodity groups that perform their functions without moving parts or without a change in configuration or properties (referred to as “passive” components). These components were identified using the guidance of NEI 95-10 and the Electric Power Research Institute (EPRI) License Renewal Electrical Handbook.

(3) The 10 CFR 54.21(a)(1)(ii) screening criterion was applied to those components and commodity groups that were not previously eliminated by the application of the 10 CFR 54.21(a)(1)(i) screening criterion.

2.1.5.4.2 Staff Evaluation

The staff reviewed the applicant’s methodology used for electrical screening in LRA Section 2.1.6.1 and subsections, implementing procedures, bases documents, and reports. The staff confirmed that the applicant used the screening process described in these documents along with the information contained in NEI 95-10, Appendix B and the SRP-LR to identify the electrical and I&C components subject to an AMR.

The staff determined that the applicant had identified commodity groups which were found to meet the passive criteria in accordance with NEI 95-10. In addition, the staff determined that the applicant evaluated the identified, passive commodities to determine whether they were subject to replacement based on a qualified life or specified time period (short-lived), or not subject to replacement based on a qualified life or specified time period (long-lived). The applicant had correctly determined that the remaining passive, long-lived components were determined to be subject to an AMR.

The staff reviewed selected portions of the UFSAR, the plant component database, CLB documentation, documents, procedures, drawings, specifications, and selected scoping and screening reports. The staff conducted discussions with the applicant's license renewal team and reviewed documentation pertinent to the screening process. The staff assessed whether the electrical screening methodology outlined in the LRA and procedures was appropriately implemented and if the scoping results were consistent with CLB requirements. During the scoping and screening methodology audit, the staff discussed the screening methodology with the applicant and reviewed the applicant's screening reports for selected systems to verify proper implementation of the screening process. Based on these audit activities, the staff did not identify any discrepancies between the methodology documented and the implementation results.

2.1.5.4.3 Conclusion

On the basis of its review of the LRA, implementing procedures, selected portions of the UFSAR, plant component database, the CLB documentation, procedures, drawings, specifications and selected scoping and screening reports, discussion with the applicant, and a sample of the results of the screening methodology, the staff concludes that the applicant's methodology for identification of electrical components subject to an AMR is in accordance with the requirements of 10 CFR 54.21(a)(1) and, therefore, is acceptable.

2.1.5.5 Screening Methodology Conclusion

On the basis of its review of the LRA, implementing procedures, discussions with the applicant's staff, and a sample review of screening results, the staff concludes that the applicant's screening methodology is consistent with the guidance contained in the SRP-LR, and the applicant identified those passive, long-lived components within the scope of license renewal that are subject to an AMR. The staff concludes that the applicant's methodology is consistent with the requirements of 10 CFR 54.21(a)(1) and, therefore, is acceptable.

2.1.6 Summary of Evaluation Findings

On the basis of its review of the information presented in LRA Section 2.1, the supporting information in the scoping and screening implementing procedures and reports, the information presented during the scoping and screening methodology audit, discussions with the applicant, and the applicant's response dated May 24, 2010, to the staff's RAIs, the staff concludes that the applicant's scoping and screening methodology, including the description and justification for its methodology, are consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). From this review, the staff concludes that the applicant's methodology for identifying systems and structures within the scope of license renewal and SCs requiring an AMR is acceptable.

2.2 Plant-Level Scoping Results

2.2.1 Introduction

LRA Section 2.1 describes the methodology for identifying systems and structures within the scope of license renewal. In LRA Section 2.2, the applicant used the scoping methodology to determine which systems and structures must be included within the scope of license renewal.

2.2.2 Summary of Technical Information in the Application

The staff reviewed the plant-level scoping results to determine whether the applicant has properly identified the following three groups:

- Safety-related SSCs which are those relied upon to remain functional during and following DBEs, as required by 10 CFR 54.4(a)(1).
- All nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of any safety-related functions, as required by 10 CFR 54.4(a)(2).
- All SSCs relied on in safety analyses of plant evaluations to perform a function that demonstrates compliance with the NRC regulations for fire protection, pressurized thermal shock, ATWS, and SBO, as required by 10 CFR 54.4(a)(3).

LRA Table 2.2-1 lists those mechanical systems, electrical and I&C systems, and structures that are within the scope of license renewal. Also in LRA Table 2.2-1, the applicant listed the systems and structures that do not meet the criteria specified in 10 CFR 54.4(a) and are excluded from the scope of license renewal. Based on the DBEs considered in the CLB, other CLB information relating to nonsafety-related systems and structures, and certain regulated events, the applicant identified plant-level systems and structures within the scope of license renewal as defined by 10 CFR 54.4.

2.2.3 Staff Evaluation

The purpose of the staff's evaluation was to determine whether the applicant properly identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4.

In LRA Section 2.1, the applicant described its methodology for identifying systems and structures within the scope of license renewal and subject to an AMR. The staff reviewed the scoping and screening methodology and provides its evaluation in SER Section 2.1. To verify that the applicant properly implemented its methodology, the staff's review focused on the implementation results shown in LRA Table 2.2-1 to confirm that there were no omissions of plant-level systems and structures that should be within the scope of license renewal.

The staff determined whether the applicant properly identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4. The staff reviewed selected systems and structures that the applicant did not identify as within the scope of license renewal to determine whether the systems and structures have any intended functions requiring their inclusion within the scope of license renewal. The staff's review of the applicant's implementation was conducted in accordance with the guidance in SRP-LR Section 2.2, "Plant-Level Scoping Results." The staff reviewed LRA Section 2.2 and the UFSAR supporting information to determine whether the applicant failed to identify any systems and structures within the scope of license renewal.

2.2.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that the applicant has appropriately identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4 and, therefore, is acceptable.

2.3 Scoping and Screening Results: Mechanical Systems

This section documents the staff's review of the applicant's scoping and screening results for mechanical systems. Specifically, this section describes the following mechanical systems:

- reactor vessel, internals, and reactor coolant system
- engineered safety features systems
- auxiliary systems
- steam and power conversion systems

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must list passive, long-lived SCs within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff's review focused on the implementation results. This focus allowed the staff to verify that the applicant identified the mechanical system SCs that met the scoping criteria and were subject to an AMR and that there were no omissions. The staff's evaluation of mechanical systems was performed using the evaluation methodology described in this SER and in the guidance of SRP-LR Section 2.3, and took into account, where applicable, the system functions described in the UFSAR. The objective was to determine whether the applicant has identified, in accordance with 10 CFR 54.4, components and supporting structures for mechanical systems that meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to verify that all passive, long-lived components are subject to an AMR as required by 10 CFR 54.21(a)(1).

In its scoping evaluation, the staff reviewed the LRA, applicable sections of the UFSAR, license renewal boundary drawings, and other licensing basis documents, as appropriate, for each mechanical system within the scope of license renewal. The staff reviewed relevant licensing basis documents for each mechanical system to confirm that the LRA specified all intended functions defined by 10 CFR 54.4(a). The review then focused on identifying any components with intended functions defined by 10 CFR 54.4(a) that the applicant may have omitted from the scope of license renewal.

After reviewing the scoping results, the staff evaluated the applicant's screening results. For those SCs with intended functions required by 10 CFR 54.4(a), the staff verified the applicant properly screened out only: (a) SCs that have functions performed with moving parts or a change in configuration or properties, or (b) SCs that are subject to replacement after a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For SCs not meeting either of these criteria, the staff confirmed the remaining SCs received an AMR, as required by 10 CFR 54.21(a)(1).

The staff evaluation of the mechanical system scoping and screening results applies to all mechanical systems reviewed. Those systems that required RAIs to be generated include an additional staff evaluation which specifically addresses the applicant's responses to the RAI(s).

2.3.1 Reactor Vessel, Internals, and Reactor Coolant System

LRA Section 2.3.1 describes the reactor vessel, internals, and reactor coolant system SCs subject to an AMR for license renewal. The applicant described the supporting SCs of the reactor vessel, internals, and reactor coolant system in the following LRA sections:

- LRA Section 2.3.1.1, “Control Rods”
- LRA Section 2.3.1.2, “Fuel Assemblies”
- LRA Section 2.3.1.3, “Nuclear Boiler Instrumentation”
- LRA Section 2.3.1.4, “Reactor Internals”
- LRA Section 2.3.1.5, “Reactor Pressure Vessel”
- LRA Section 2.3.1.6, “Reactor Recirculation System”

2.3.1.1 Control Rods

2.3.1.1.1 Summary of Technical Information in the Application

LRA Section 2.3.1.1 describes the control rods, which are replaceable, mechanical components consisting of cruciform-shaped stainless steel assemblies containing neutron-absorbing material designed to be used for flux shaping and for reactivity control during reactor startup, power level changes, and shutdown.

The purpose of the control rods is to absorb neutrons in the reactor core, thereby providing the means to adjust core power shape, compensate for reactivity changes caused by fuel and burnable poison depletion, and fully shut down the nuclear reaction.

The control rods are comprised of four stainless steel wings assembled in a cruciform configuration. Each wing assembly is constructed of stainless steel material with boron carbide and/or hafnium as absorbing material. Each control rod has a handle assembly and a velocity limiter. The velocity limiter restricts the free-fall velocity of the control rod to preclude system damage in the event of a rod drop casualty.

Near the end of the operating cycle, all control rods are withdrawn to maintain rated reactor power until scheduled reactor shutdown for refueling. Control rod absorption of neutrons chemically depletes the absorber material, and control rod lifetime is monitored. Upon reaching prescribed thresholds, control rods are scheduled for replacement during refueling outages.

LRA Table 2.3.1-1 identifies the component types within the scope of license renewal but has identified no component types subject to an AMR.

2.3.1.1.2 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found that because the control rods are active components, there are no components subject to an AMR. Based on its review, the staff concludes that the applicant has adequately identified the control rod mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.2 Fuel Assemblies

2.3.1.2.1 Summary of Technical Information in the Application

LRA Section 2.3.1.2 describes the fuel assemblies, which are high integrity components containing the fissionable material that sustains the nuclear reaction when the reactor core is made critical.

Each fuel assembly is comprised of a fuel bundle and a channel that surrounds it. The fuel rods of each bundle are spaced and supported in a square array. The assembly is held together by upper and lower tie plates that give it structural support in the reactor and facilitate removal of the assembly during refueling.

The bundle channel is fabricated from Zircaloy and provides the flow path outer periphery for the bundle coolant flow, supplies structural stiffness to the bundle and transmits seismic loadings to the core internal structures, provides a heat sink during a loss of coolant accident (LOCA), and supplies a surface for control rod guidance within the reactor core.

The purpose of the fuel assemblies is to allow efficient heat transfer from the nuclear fuel to the reactor coolant and to maintain structural integrity providing a controllable, coolable bundle geometry and fission product barrier.

LRA Table 2.3.1-2 identifies the component types within the scope of license renewal but has identified no component types subject to an AMR.

2.3.1.2.2 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found that because the fuel assemblies are active components, there are no components subject to an AMR. Based on its review, the staff concludes that the applicant has adequately identified the control rod mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.3 Nuclear Boiler Instrumentation

2.3.1.3.1 Summary of Technical Information in the Application

LRA Section 2.3.1.3 describes the nuclear boiler instrumentation system, which is designed to provide the means to measure parameters of reactor vessel level, pressure, temperature, core flow, core plate differential pressure, primary containment (drywell) pressure, main condenser pressure, and main turbine first stage pressure.

The purpose of the nuclear boiler instrumentation system is to provide signals to the reactor protection system and the various emergency core cooling system (ECCS) logic to initiate protective system functions such as reactor scram, emergency core cooling, primary containment isolation, recirculation pump trip, and alternate rod insertion.

Nuclear boiler instrumentation is comprised of sensing lines, flow restricting orifices, isolation valves, excess flow check valves, transmitters, condensing chambers, and instruments. Reactor vessel level is measured by comparing the actual water level in the reactor vessel (variable leg) to a constant height of water in the reference leg. Reactor vessel pressure is measured by pressure instruments using the same piping that is used to measure the pressure in the reactor vessel level instrument reference legs. Reactor vessel temperature is measured through a thermocouple mounted in specific locations throughout the reactor vessel. Core plate differential pressure is measured by instrumentation that compares pressure below and above the core plate. Core flow is measured by instrumentation that determines the total flow through the jet pumps. Primary containment pressure is measured by pressure transmitters connected to sensing lines open to the primary containment atmosphere. Main condenser pressure and main turbine first stage pressure are measured by pressure transmitters connected to sensing lines.

LRA Table 2.3.1-3 identifies the component types within the scope of license renewal and subject to an AMR.

2.3.1.3.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the nuclear boiler instrumentation mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.4 Reactor Internals

2.3.1.4.1 Summary of Technical Information in the Application

LRA Section 2.3.1.4 describes the reactor internals system, which is a mechanical system whose components are contained within the reactor pressure vessel (RPV) and extend beyond the RPV to form a portion of the reactor coolant boundary.

The purpose of the reactor internals system is to provide support for the core and other internal components, maintain the fuel in a coolable geometry during normal and accident conditions, provide proper distribution of the coolant delivered to the vessel, provide a floodable volume, and maintain the reactor coolant pressure boundary.

The reactor internals consist of the core shroud, core plate, core spray lines and spargers, fuel supports, control rod drive assemblies, instrumentation dry tubes, jet pump assemblies, steam dryer assembly, and the top guide.

LRA Table 2.3.1-4 identifies the component types within the scope of license renewal and subject to an AMR.

2.3.1.4.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the reactor internals mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.5 Reactor Pressure Vessel

2.3.1.5.1 Summary of Technical Information in the Application

LRA Section 2.3.1.5 describes the RPV, which is designed to contain the reactor coolant and facilitate the transfer of heat from the core. The vessel provides a floodable volume to assure adequate core cooling in the event of a breach in the coolant boundary external to the RPV.

The purpose of the RPV is to form part of the reactor coolant boundary and to serve as a radioactive material barrier during normal operations and following abnormal operational transients and accidents.

The RPV contains the reactor core, the reactor internals, and reactor core coolant moderator. It consists of the following major components: the cylindrical shell and flange, the top head and flange, the bottom head, welds, nozzles, safe ends, closure studs, internal supports, and external supports, including the skirt assembly.

LRA Table 2.3.1-5 identifies the component types within the scope of license renewal and subject to an AMR.

2.3.1.5.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the RPV mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.6 Reactor Recirculation System

2.3.1.6.1 Summary of Technical Information in the Application

LRA Section 2.3.1.6 describes the reactor recirculation system, which provides forced circulation of reactor coolant through the core for heat removal and the ability to maintain a reactor vessel floodable volume in the event of a piping integrity failure.

The purpose of the reactor recirculation system is to provide a means to control reactor power within a limited range without the need for manipulation of the control rods. It delivers recirculated drive water flow to the reactor vessel through two separate pumped loops, each with an individually controllable variable speed pump, 5 jet pump risers, and 10 jet pumps.

The reactor recirculation system consists of the reactor recirculation main loop piping, recirculation pumps and motors, recirculation motor generator sets, recirculation system flow control, and recirculation pump trip logic. The path of coolant through each of these loops is as follows: reactor coolant enters the vessel annulus region and then exits the reactor vessel through the loop's outlet nozzle and into the recirculation pump suction piping. The coolant then goes through the pump and out into the discharge piping, which feeds into five jet pump risers. These risers distribute the flow into the vessel, where it discharges the coolant into two jet pumps. The coolant flow mixes with coolant from the annulus region, and this mixture travels through the orifices at the bottom of the core and flows up through the core where the bulk boiling produces steam. This steam-water mixture enters the moisture separators and the steam dryers, where the water is separated from the steam. The water flows downward into the annulus region where the flow path is repeated.

LRA Table 2.3.1-6 identifies the component types within the scope of license renewal and subject to an AMR.

2.3.1.6.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the reactor recirculation system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features

LRA Section 2.3.2 describes the engineered safety features system SCs subject to an AMR for license renewal. The applicant described the supporting SCs of the engineered safety features system in the following LRA sections:

- LRA Section 2.3.2.1, “Automatic Depressurization System (ADS)”
- LRA Section 2.3.2.2, “Containment Hydrogen Recombiner System”
- LRA Section 2.3.2.3, “Core Spray System”
- LRA Section 2.3.2.4, “Filtration, Recirculation, and Ventilation System”
- LRA Section 2.3.2.5, “High Pressure Coolant Injection (HPCI) System”
- LRA Section 2.3.2.6, “Hydrogen and Oxygen Analyzer System”
- LRA Section 2.3.2.7, “Reactor Core Isolation Cooling (RCIC) System”
- LRA Section 2.3.2.8, “Residual Heat Removal (RHR) System”
- LRA Section 2.3.2.9, “Vacuum Relief Valve System”

2.3.2.1 Automatic Depressurization System

2.3.2.1.1 Summary of Technical Information in the Application

LRA Section 2.3.2.1 describes the ADS, which is a standby ECCS designed to automatically depressurize the RPV during a small break LOCA when the HPCI system is inoperable or cannot maintain water level in the vessel and pressure remains above the design capability of the low-pressure ECCSs. It accomplishes this by opening 5 out of 14 nuclear pressure relief system relief valves to depressurize the RPV to the suppression pool.

The purpose of the ADS is to provide automatic depressurization of the RPV in the event of a small break in the RPV pressure boundary where coolant inventory cannot be maintained and RPV pressure remains above the design capability of the low-pressure ECCSs.

LRA Table 2.3.2-1 identifies the component types within the scope of license renewal but has identified no component types subject to an AMR.

2.3.2.1.2 Conclusion

Based on the results of the staff evaluation of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the ADS mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.2 Containment Hydrogen Recombiner System

2.3.2.2.1 Summary of Technical Information in the Application

LRA Section 2.3.2.2 describes the containment hydrogen recombiner system, which is comprised of two separate and redundant trains, each capable of recombining hydrogen and oxygen at a rate in excess of their expected post-LOCA production. Each containment hydrogen recombiner train has a blower assembly, which provides the motive force to transport the drywell atmosphere to the recombiner reaction chamber for processing and then provides a return flow path to the torus. Each train also has a main heater that is used to raise the operating temperature to the reaction temperature required to allow spontaneous recombination of hydrogen and oxygen. The containment hydrogen recombiner system is designed to control hydrogen and oxygen concentrations in the primary containment postulated to be generated following a beyond DBA.

The containment hydrogen recombiner system contains safety-related components relied upon to remain functional during and following DBEs. In addition, the system is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for EQ (10 CFR 50.49).

LRA Table 2.3.2-2 identifies the components subject to an AMR for the containment hydrogen recombiner system by component type and intended function.

2.3.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.2, LRA Table 2.3.2-2, and UFSAR Sections 6.2.5 and 7.3.1.1.6 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant has not omitted from the scope of license renewal any components with intended functions required by 10 CFR 54.4(a). The staff then reviewed those components that the applicant has identified as within the scope of license renewal to verify that the applicant has not omitted any passive and long-lived components subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.2.2 identified areas where additional information was necessary in order to complete its review of the applicant's scoping and screening results.

By letter dated March 22, 2010, the staff issued RAI 2.3.2.2-1 which notes that the component type "Fan Housing" on the license renewal drawing is enclosed by another housing made of carbon steel. The staff requested that the applicant provide the purpose of the enclosure around the fan and state whether it is within the scope of license renewal, in accordance with 10 CFR 54.4(a), and if it is subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

By letter dated April 6, 2010, the applicant stated that:

> The blower unit (Blower AV-215) as shown on license Renewal Drawing LR-M-58, Sheet 1 Rev. 0 is comprised of an inner blower/motor unit and an outer carbon steel housing. The purpose of the outer blower unit housing is to provide a leak tight pressure boundary enclosure around the blower/motor assembly to eliminate any potential for hydrogen gas mixture leak to the surrounding environment. Both the outer housing and the inner fan housing provide a pressure boundary function, are within scope of license renewal, and are subject to aging management review. They are both captured as component type "Fan Housing" in Tables 2.3.2-2 and 3.2.2-1.

The staff's review found the applicant's response to RAI 2.3.2.2-1 acceptable because the response provided the purpose of the enclosure around the fan and stated that it is within the scope of license renewal and subject to an AMR.

2.3.2.2.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the containment hydrogen recombiner system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.3 Core Spray System

2.3.2.3.1 Summary of Technical Information in the Application

LRA Section 2.3.2.3 describes the core spray system, which is a low-pressure ECCS designed to provide cooling water for removal of decay heat from the reactor core following a postulated LOCA. Large to intermediate pipe breaks in the reactor coolant system relieve sufficient pressure to permit the core spray system to operate to limit fuel cladding maximum temperature. Core spray also functions in conjunction with the ADS during intermediate to small pipe breaks in the reactor coolant system to limit fuel cladding maximum temperature.

The purpose of the core spray system is to provide for the post-LOCA removal of decay heat from the reactor core so that fuel clad temperature limits are maintained for the entire spectrum of postulated LOCAs. The core spray system achieves its purpose by delivering a low-pressure spray pattern over the fuel following a LOCA, which limits the cladding temperature. The core spray system can be initiated automatically by either reactor low water level, or high drywell well level, or it can be initiated manually. The core spray system delivers cooling water independent of other engineered safety systems, and it can also be operated on emergency power.

The core spray system is comprised of two independent cooling loops, each of which contain two centrifugal pumps, spray sparger, and associated valves and piping. The main flow path for each core spray loop takes suction from the suppression pool through two core spray pumps, continuing through the two outboard motor isolation valves, through the inboard air operated stop check valve, and into the reactor vessel for discharge onto the core through the associated spray sparger. The core spray system can also take suction from the condensate storage tank.

LRA Table 2.3.2-3 identifies the components subject to an AMR for the core spray system by component type and intended function.

2.3.2.3.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the core spray system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.4 Filtration, Recirculation, and Ventilation System

2.3.2.4.1 Summary of Technical Information in the Application

LRA Section 2.3.2.4 describes the filtration, recirculation, and ventilation system, which consists of two subsystems, the recirculation system and the ventilation system, that are required to perform post-accident, safety-related functions simultaneously. The recirculation system, located inside the reactor building, is designed to recirculate and filter the air in the reactor building following a LOCA, or other high radioactivity accident, to reduce offsite doses significantly below 10 CFR Part 100 guidelines. The ventilation system, also located inside the reactor building, maintains the building at a negative pressure with respect to the outdoors. The system takes suction from the discharge duct of the recirculation system and discharges the air through filters to the outdoors via a vent at the top of the reactor building.

The filtration, recirculation, and ventilation system contains safety-related components relied upon to remain functional during and following DBEs. In addition, the filtration, recirculation, and ventilation system performs functions that support EQ and SBO.

LRA Table 2.3.2-4 identifies the components subject to an AMR for the filtration, recirculation, and ventilation system by component type and intended function.

2.3.2.4.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the filtration, recirculation, and ventilation system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.5 High Pressure Coolant Injection System

2.3.2.5.1 Summary of Technical Information in the Application

LRA Section 2.3.2.5 describes the HPCI system, which is part of the ECCS. The main function of the HPCI system is to protect the core in the case of a small break in the reactor coolant pressure boundary which does not cause rapid depressurization. This permits the plant to be safely shut down, by maintaining sufficient reactor vessel water inventory while the reactor vessel is depressurized. Initiation of HPCI occurs upon receipt of a high drywell pressure or low-low reactor water level signal. The HPCI system can be operated on direct current (DC) emergency power.

The primary purpose of the HPCI system is to provide sufficient coolant to the reactor vessel to prevent excessive fuel clad temperatures in the event of a small break LOCA that does not result in rapid depressurization of the reactor vessel. The HPCI system accomplishes this purpose by delivering sufficient high pressure flow to maintain reactor vessel inventory and ensures that the reactor core is not uncovered. The HPCI system operation is initiated automatically by either reactor low-low water level, high drywell pressure, or can be initiated manually.

The HPCI system contains a turbine driven pump. Steam is extracted from the main steam lines to run the pump. The turbine exhaust is routed to the suppression pool. Because of this, it is capable of supplying water even during an SBO. Water suction can be aligned to the condensate storage tank or to the suppression pool. The water then gets pumped to the suction of the HPCI pump. The HPCI pump discharges to the RPV through the core spray sparger connected to core spray pumps “A” and “C.” The pump also discharges to the reactor vessel through the feedwater line “A” header. There is also a lube oil system for HPCI which provides oil to the main pump bearings, the turbine stop and control valve, and multiple other components.

LRA Table 2.3.2-5 identifies the components subject to an AMR for the HPCI system by component type and intended function.

2.3.2.5.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the HPCI system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.6 Hydrogen and Oxygen Analyzer System

2.3.2.6.1 Summary of Technical Information in the Application

LRA Section 2.3.2.6 describes the hydrogen and oxygen analyzer system, which is a gas sampling system, consisting of two identical redundant trains, designed to monitor the hydrogen and oxygen concentration in the primary containment during accident conditions. The hydrogen and oxygen analyzer system includes a permanently connected torus supplementary oxygen analyzer panel in the “A” train between the torus sample incoming and return lines. Additionally, the hydrogen and oxygen analyzer system includes a portable drywell supplementary oxygen analyzer panel that can be connected through the leak detection and radiation monitoring system.

The purpose of the hydrogen and oxygen analyzer system is to monitor the primary containment atmosphere to ensure that oxygen and hydrogen levels do not approach flammability limits. The hydrogen and oxygen analyzer system accomplishes this purpose post-accident and during normal power operations. During post-accident operation, the hydrogen and oxygen analyzer system processes a drywell atmosphere sample through one of two redundant hydrogen and oxygen analyzer loops. During normal power operation, the hydrogen and oxygen analyzer system is in the standby mode, except for calibration of maintenance, and the supplementary oxygen monitoring portion of the hydrogen and oxygen analyzer system is in service to monitor the oxygen concentration of the atmosphere in the drywell and torus areas. The purpose of the supplementary oxygen analyzers is to provide an alternate method of monitoring torus and drywell oxygen concentration.

LRA Table 2.3.2-6 identifies the components subject to an AMR for the hydrogen and oxygen analyzer system by component type and intended function.

2.3.2.6.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the hydrogen and oxygen analyzer system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.7 Reactor Core Isolation Cooling System

2.3.2.7.1 Summary of Technical Information in the Application

LRA Section 2.3.2.7 describes the RCIC system, which is a high pressure, safety-related system designed to ensure sufficient reactor water inventory is maintained in the reactor vessel to allow for adequate core cooling. The primary purpose of the RCIC system is to provide sufficient coolant to the reactor vessel to prevent excessive fuel cladding temperatures during a reactor shutdown in which feedwater flow is not available. The RCIC can be activated automatically by reactor low-low water level or manually initiated. RCIC can be operated on DC emergency power.

The purpose of the RCIC system is to provide sufficient coolant to the reactor vessel to prevent excessive fuel clad temperatures during a reactor shutdown in which feedwater flow is not available. The RCIC system accomplishes this purpose by delivering sufficient high pressure flow to maintain reactor vessel inventory and to ensure that the reactor core is not uncovered. The RCIC system operation is initiated automatically by reactor low-low water level or can be initiated manually.

The RCIC system has a steam-driven turbine pump and normally takes suction from the condensate storage tanks. It can also take suction from the suppression pool. The water is injected into the reactor vessel via a feedwater line. The steam to run the pump is extracted from the main steam lines. The steam is discharged to the suppression pool, which allows the pump to run during an SBO.

LRA Table 2.3.2-7 identifies the components subject to an AMR for the RCIC system by component type and intended function.

2.3.2.7.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the RCIC system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.8 Residual Heat Removal System

2.3.2.8.1 Summary of Technical Information in the Application

LRA Section 2.3.2.8 describes the RHR system, which is a low-pressure ECCS designed to provide cooling water for the removal of fission product heat from the reactor core and primary containment following a postulated DBE or normal operation.

The RHR system has three primary and two secondary functions of operation. The first two primary functions of the RHR system are to provide for the post-DBEs fission product heat removal from the reactor core so that the fuel clad temperature limit is not exceeded and heat is removed from the primary containment to ensure structural pressure and temperature limits are not exceeded. The RHR system accomplishes the two primary purposes by the low-pressure coolant injection and containment spray modes which deliver low-pressure coolant to the reactor vessel and to primary containment, which limits peak clad temperature to less than the maximum allowable limit, and to primary containment, maintaining the structure temperature and pressure less than its maximum design limit. Fission product decay heat is removed from the core and primary containment by the RHR system and is transported to the torus. The RHR heat exchangers remove the heat from the torus and transfer the heat to the safety auxiliary cooling system, which is evaluated in the closed-cycle cooling water system.

The third primary function of the RHR system is to remove the decay and sensible heat from the reactor primary system to permit cold shutdown for refueling. The RHR system accomplishes this purpose in the shutdown cooling mode by manually opening valves that have piping interconnections with reactor recirculation system suction piping, directing flow through the RHR heat exchangers which removes heat from the reactor and returns the flow to reactor recirculation discharge piping, therefore, allowing shutdown.

The two secondary functions of the RHR system are to augment fuel pool cooling by removing decay heat of the spent fuel and to provide an alternate source of water from a non-nuclear steam supply system (NSSS) intertie between the station service water system and the RHR system piping, which allows water to flood the reactor containment during the period following a LOCA.

The RHR system consists of four main pumps, two heat exchangers, associated piping, and valves. There are two physically separated loops each consisting of two pumps and one heat exchanger. The two separated loops prevent a single failure from causing both loops to be inoperable and thus the entire system being inoperable. The RHR system can: (1) restore and maintain the coolant inventory in the reactor vessel to cool the core in the case of a LOCA, (2) provide drywell and suppression pool cooling in post-LOCA situations, and (3) provide RHR when the main heat sink is unavailable, such as during normal shutdown. The RHR system can operate in six modes: (1) ECCS low-pressure coolant injection, (2) primary containment spray, (3) torus cooling, (4) shutdown cooling, (5) fuel pool cooling, and (6) alternate injection.

LRA Table 2.3.2-8 identifies the components subject to an AMR for the RHR system by component type and intended function.

2.3.2.8.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the RHR system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.9 Vacuum Relief Valve System

2.3.2.9.1 Summary of Technical Information in the Application

LRA Section 2.3.2.9 describes the vacuum relief valve system, which consists of two independent subsystems: the torus to drywell pressure relief subsystem and the reactor building to torus pressure relief subsystem.

The primary containment is provided with a vacuum relief valve system to equalize the pressure between the drywell and the torus, and between the torus and the reactor building. The vacuum relief valve system assures that the external design pressure limits of the two chambers are not exceeded. The DBA is the complete instantaneous circumferential break of one of the recirculation suction lines while the reactor is at rated power. The air-stream mixture is vented to the torus. Within the first few seconds, drywell air is swept into the torus water space. Because of the high velocity steam within the vents, the air cannot diffuse back into the drywell and it is effectively forced into the torus water space. After blowdown is complete, steam is present in the drywell. As the steam condenses on various surfaces and the drywell spray is activated, the drywell pressure drops. This allows the torus to drywell vacuum breakers to open and admit the gas from the torus air space into the drywell, thus equalizing the pressures.

The torus to drywell pressure relief subsystem is designed to prevent torus water from backing up into the drywell during various reactor leakage and suppression condensation modes. The purpose of the torus to drywell pressure relief subsystem is to prevent the drywell pressure from dropping significantly below the pressure in the torus airspace, and to prevent exceeding design external pressures of the drywell. The torus and drywell pressure relief subsystem is comprised of vacuum breakers that accomplish their purpose by automatically venting non-condensable gas (carryover to the torus during an accident) back to the drywell from the torus.

The reactor building to torus pressure relief subsystem limits the torus negative pressure relative to the reactor building pressure. This subsystem limits drywell negative pressures relative to the reactor building pressure and permits gas flow only inward from the reactor building to the primary containment. The reactor building to torus pressure relief subsystem is comprised of vacuum breakers that accomplish their purpose by opening automatically at a predetermined differential pressure.

LRA Table 2.3.2-9 identifies the components subject to an AMR for the vacuum relief valve system by component type and intended function.

2.3.2.9.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the vacuum relief valve system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3 Auxiliary Systems

LRA Section 2.3.3 identifies the auxiliary system SCs subject to an AMR for license renewal. The applicant described the supporting SCs of the auxiliary systems in the following LRA sections:

- LRA Section 2.3.3.1, “Chilled Water System”
- LRA Section 2.3.3.2, “Closed Cycle Cooling Water System”
- LRA Section 2.3.3.3, “Compressed Air System”
- LRA Section 2.3.3.4, “Containment Inerting and Purging System”
- LRA Section 2.3.3.5, “Control Area Chilled Water System”
- LRA Section 2.3.3.6, “Control Rod Drive System”
- LRA Section 2.3.3.7, “Control Room and Control Area HVAC Systems”
- LRA Section 2.3.3.8, “Cranes & Hoists”
- LRA Section 2.3.3.9, “Equipment and Floor Drainage System”
- LRA Section 2.3.3.10, “Fire Protection System”
- LRA Section 2.3.3.11, “Fire Pump House Ventilation System”
- LRA Section 2.3.3.12, “Fresh Water Supply System”
- LRA Section 2.3.3.13, “Fuel Handling and Storage System”
- LRA Section 2.3.3.14, “Fuel Pool Cooling and Cleanup System”
- LRA Section 2.3.3.15, “Hardened Torus Vent System”
- LRA Section 2.3.3.16, “Hydrogen Water Chemistry System”
- LRA Section 2.3.3.17, “Leak Detection and Radiation Monitoring System”
- LRA Section 2.3.3.18, “Makeup Demineralizer System”
- LRA Section 2.3.3.19, “Primary Containment Instrument Gas System”
- LRA Section 2.3.3.20, “Primary Containment Leakage Rate Testing System”
- LRA Section 2.3.3.21, “Process and Post-Accident Sampling Systems”
- LRA Section 2.3.3.22, “Radwaste System”
- LRA Section 2.3.3.23, “Reactor Building Ventilation System”
- LRA Section 2.3.3.24, “Reactor Water Cleanup System”
- LRA Section 2.3.3.25, “Remote Shutdown Panel Room HVAC System”
- LRA Section 2.3.3.26, “Service Water Intake Ventilation System”
- LRA Section 2.3.3.27, “Service Water System”
- LRA Section 2.3.3.28, “Standby Diesel Generator Area Ventilation Systems”
- LRA Section 2.3.3.29, “Standby Diesel Generators and Auxiliary Systems”
- LRA Section 2.3.3.30, “Standby Liquid Control System”
- LRA Section 2.3.3.31, “Torus Water Cleanup System”
- LRA Section 2.3.3.32, “Traversing Incore Probe System”

Auxiliary Systems Generic Requests for Additional Information. In a letter dated April 15, 2010, the staff issued RAI 2.3-01 and noted instances where it was unable to identify the license renewal boundary because: (1) continuations were not provided or are incorrect, or (2) the continuation drawing was not provided. The applicant was requested to provide additional information on the continuations of the license renewal boundary.

In a response dated May 11, 2010, the applicant provided sufficient additional information to locate the license renewal boundaries. When drawings do not exist, the applicant stated that there were no additional component types within the license renewal boundary that are subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3-01 acceptable because the applicant provided the continuation locations or stated that there are no additional component types subject to an AMR within the license renewal boundary. Therefore, the staff's concern described in RAI 2.3-01 is resolved.

2.3.3.1 Chilled Water System

2.3.3.1.1 Summary of Technical Information in the Application

LRA Section 2.3.3.1 describes the chilled water system, which is a closed-loop system designed to provide demineralized cooling water to plant air handling and cooling units during normal operation in the reactor, auxiliary, and turbine buildings.

The purpose of the chilled water system is to remove heat from the plant's cooling coils and coolers during various modes of reactor operation. The chilled water system accomplishes this purpose by transferring heat from the plant's cooling coils and coolers to the chiller units, which reject the heat from the chilled water to the turbine auxiliary cooling system portion of the closed-cycle cooling water system.

LRA Table 2.3.3-1 identifies the components subject to an AMR for the chilled water system by component type and intended function.

2.3.3.1.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the chilled water system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.2 Closed-Cycle Cooling Water System

2.3.3.2.1 Summary of Technical Information in the Application

LRA Section 2.3.3.2 describes the closed-cycle cooling water system, which is a normally operating closed-loop mechanical system designed to provide demineralized cooling water to various safety-related and nonsafety-related equipment within the plant. The closed-cycle cooling water system consists of the following two independent plant systems: the safety and turbine auxiliary cooling plant system and the reactor auxiliary cooling plant system.

The safety and turbine auxiliary cooling plant system is designed to provide a heat sink for engineering safety features equipment and turbine generator auxiliary equipment by circulating cooling water in a closed-loop system. The purpose of the safety auxiliary cooling plant system is to remove heat from safety-related loads located within the reactor building and auxiliary building during various modes of reactor operation. The purpose of the turbine auxiliary cooling plant system is to remove heat from nonsafety-related loads within the turbine building to meet the turbine generator auxiliary cooling requirements during normal operation and normal shutdown conditions. The safety and turbine auxiliary cooling plant system accomplishes its purpose by transferring heat from these nonsafety-related loads to the service water system, through the safety auxiliary cooling plant system heat exchangers.

The purpose of the reactor auxiliary cooling plant system is to remove heat from non-essential (non-engineering safety feature) loads located in the reactor building, auxiliary building, radwaste building, and turbine building that carry radioactive fluids. The reactor auxiliary cooling plant system accomplishes its purpose by transferring heat from these loads to the service water system, through the reactor auxiliary cooling plant system heat exchangers.

LRA Table 2.3.3-2 identifies the components subject to an AMR for the closed-cycle cooling water system by component type and intended function.

2.3.3.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.2, UFSAR Sections 9.2.2 and 9.2.8, and the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

In a letter dated April 15, 2010, the staff issued RAI 2.3.3.2-01 and noted that license renewal drawing LR-M-13-1, sheet 1, at locations D-3 and D-5, shows lines 4”-HBB-024 and 4”-HBB-023, designated as 10 CFR 54.4(a)(1), connected to lines 6”-HBD-003 and 4”-HBD-018, designated as 10 CFR 54.4(a)(2). The applicant was requested to provide additional information to locate the anchors for the 6”-HBD-003 and 4”-HBD-018 lines between the end of the (a)(2) scoping boundary and the safety-nonsafety interface.

The applicant's response, dated May 11, 2010, described the location of the anchors, which are within the existing (a)(2) scoping boundary. This conforms to the applicant's methodology and did not result in the inclusion of any additional components within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.2-01 is resolved.

2.3.3.2.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the closed-cycle cooling water system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.3 Compressed Air System

2.3.3.3.1 Summary of Technical Information in the Application

LRA Section 2.3.3.3 describes the compressed air system, which is a normally operating system designed to provide clean and dry compressed air in support of plant operation.

The compressed air system consists of the service and instrument air plant system. The purpose of the service and instrument air plant system is to provide clean and dry compressed air to pneumatically-operated instruments and valves. To accomplish this purpose, the system takes air from outside of the turbine building and processes the air through air compressors, intercoolers, aftercoolers, moisture separators, air receivers, and air dryers for distribution to components in support of plant operation.

LRA Table 2.3.3-3 identifies the components subject to an AMR for the compressed air system by component type and intended function.

2.3.3.3.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the compressed air system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.4 Containment Inerting and Purging System

2.3.3.4.1 Summary of Technical Information in the Application

LRA Section 2.3.3.4 describes the containment inerting and purging system, which is a pressurized gas system designed to maintain an inert atmosphere within the primary containment during plant operations to preclude energy releases from a possible hydrogen-oxygen reaction following a postulated LOCA. The inert environment also precludes the possibility of an exposure fire within the primary containment.

The purpose of the containment inerting and purging system is to provide a means of reducing the oxygen concentration in the containment for normal power operations and a means of reestablishing oxygen concentration to normal life supporting levels to allow access to the primary containment. To ready the primary containment for power operation, the containment inerting and purging system accomplishes inerting by introducing nitrogen from the liquid nitrogen vaporizer to displace the oxygen from the free volume in the primary containment. The containment inerting and purging system depends on the drywell air cooling system to provide effective containment atmosphere mixing, since the containment inerting and purging system does not have any fans. Also, the containment inerting and purging system depends on the torus to drywell portion of the vacuum relief valve system for effective mixing of the torus atmosphere.

To ready the primary containment for shutdown, the containment inerting and purging system accomplishes purging and de-inerting through interfacing with the containment prepurge cleanup system portion of the reactor building ventilation system.

LRA Table 2.3.3-4 identifies the components subject to an AMR for the containment inerting and purging system by component type and intended function.

2.3.3.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.4, LRA Table 2.3.3-4, and UFSAR Section 6.2.5.2.1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant has not omitted from the scope of license renewal any components with intended functions required by 10 CFR 54.4(a). The staff then reviewed those components that the applicant has identified as within the scope of license renewal to verify that the applicant has not omitted any passive and long-lived components subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.4 identified areas where additional information was necessary in order to complete its review of the applicant's scoping and screening results.

In a letter dated March 22, 2010, the staff issued RAI 2.3.3.4-1 requesting that the applicant clarify if valve numbers V024, V025, and V026 shown on license renewal drawings LR-M-57-1, sheet 1 and LR-M-76-1, sheet 1 are the same and if they are within the scope of license renewal.

By letter dated April 6, 2010, the applicant stated that the valves are the same and within the scope of license renewal.

The staff's review found the applicant's response to RAI 2.3.3.4-1 acceptable because the applicant provided the requested clarification and stated that the subject valves are within the scope of license renewal. The staff's concern described in RAI 2.3.3.4-1 is resolved.

2.3.3.4.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the containment inerting and purging system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.5 Control Area Chilled Water System

2.3.3.5.1 Summary of Technical Information in the Application

LRA Section 2.3.3.5 describes the control area chilled water system, which is a normally operating mechanical system designed to provide chilled water to plant ventilation cooling coils. The control area chilled water system consists of two plant systems: control room chilled water system and the safety-related panel room chilled water system.

The purpose of the control area chilled water system is to provide cooling water to the safety-related and nonsafety-related ventilation systems for the control room, control area heating ventilation and air conditioning (HVAC) system, and the standby diesel generator area ventilation system.

The control area chilled water system accomplishes this by providing a continuous supply of chilled water to the cooling coils in the control room, control area ventilation system, and the standby diesel generator area ventilation system during normal and accident conditions.

Each of the control area chilled water plant systems consists of two independent and fully redundant chilled water loops. The redundant trains will start on one of the following conditions: low flow conditions indicated on in-service train, or either high or low chilled water supply temperatures for the operating loop.

LRA Table 2.3.3-5 identifies the components subject to an AMR for the control area chilled water system by component type and intended function.

2.3.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.5, UFSAR Section 9.2.7.2, and the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

In a letter dated April 15, 2010, the staff issued RAI 2.3.3.5-01 and noted that license renewal drawing LR-M-90-1, sheet 3, locations C-5 and H-5, shows a portion of piping within scope for 10 CFR 54.4(a)(1) up to valves V9990 and V9982. The drawing indicates that downstream of the valves, the piping is within scope for 10 CFR 54.4(a)(2) but is still Q-listed and seismic Category 1. This appears to be safety-related piping within scope for (a)(2), which would conflict with the scoping procedure described in the application. The applicant was requested to provide additional information to clarify the scoping classification.

In its response dated May 11, 2010, the applicant stated that valves V9990 and V9982 are within scope for 10 CFR 54.4(a)(1) and the Q-flags are incorrectly shown on the downstream piping, instead of on the downstream edge of the respective valves.

Based on its review and the applicant's explanation of the Q-flags, the staff finds the applicant's response to RAI 2.3.3.5-01 acceptable because the applicant clarified the scoping classification of the pipe sections in question. Therefore, the staff's concern described in RAI 2.3.3.5-01 is resolved.

2.3.3.5.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the control area chilled water system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.6 Control Rod Drive System

2.3.3.6.1 Summary of Technical Information in the Application

LRA Section 2.3.3.6 describes the control rod drive system, which is a high-pressure, low-flow system designed to rapidly insert all control rods into the core in response to manual action or an automatic signal from the reactor protection system. It also incrementally positions control rods in response to signals from the reactor manual control system.

The control rod drive system consists of the control rod drive hydraulic system and control rod drive removal and cleaning system.

The purpose of the control rod drive hydraulic system is to rapidly insert negative reactivity to shut down the reactor under accident or transient conditions and to manage reactivity in the reactor core by inserting or withdrawing control rods for power level control and flux shaping during normal operation. The control rod drive hydraulic system accomplishes this by providing water at the required operating pressures to the control rod drives for cooling and for all types of control rod motion in response to inputs from the reactor manual control system, redundant reactivity control system, and reactor protection system.

The secondary purpose of the control rod drive system is to provide a water source for pump seal operation and makeup. This includes providing reactor recirculation pump seal purge and makeup water to the reactor water level reference leg condensing chambers.

LRA Table 2.3.3-6 identifies the components subject to an AMR for the control rod drive system by component type and intended function.

2.3.3.6.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the control rod drive system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.7 Control Room and Control Area HVAC Systems

2.3.3.7.1 Summary of Technical Information in the Application

LRA Section 2.3.3.7 describes the control room and control area HVAC systems, which are mechanical systems designed to provide normal and emergency ventilation to the control room and associated areas in the auxiliary building.

The purpose of the control room and control area HVAC systems is to maintain habitability conditions within the control room envelope, maintain area temperatures within acceptable limits, maintain hydrogen concentrations for all battery rooms below 2 percent and remove smoke and noxious gases in the event of a fire. The control area ventilation system accomplishes this purpose by regulating temperature, humidity, and pressure during normal and accident conditions, and by providing adequate ventilation flow capacity.

LRA Table 2.3.3-7 identifies the components subject to an AMR for the control room and control area HVAC systems by component type and intended function.

2.3.3.7.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the control room and control area HVAC systems mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.8 Cranes and Hoists

2.3.3.8.1 Summary of Technical Information in the Application

LRA Section 2.3.3.8 describes the cranes and hoists, which consist of load handling bridge cranes, jib cranes, lifting devices, and hoists provided throughout the facility to support operation and maintenance activities. Cranes and hoists include those required to comply with the requirements of NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants, Resolution of Generic Technical Activity A36,” and hoists for handling light loads. Major cranes include the reactor building polar crane and the turbine building crane.

The reactor building polar crane services the operating floor and is used to lift heavy loads such as the reactor closure head. The crane is also used to handle new fuel and transport the spent fuel cask. The reactor building polar crane main hoist and auxiliary hoist are designed to be single failure proof in conformance with NUREG-0554, “Single Failure-Proof Cranes for Nuclear Power Plants,” and NUREG-0612. The crane is designed to include seismic loading for the operating basis earthquake (OBE) and safe-shutdown earthquake (SSE) seismic events and is classified as seismic Category I.

The turbine building crane services the operating floor and is used to lift loads to support turbine repairs or maintenance. The crane is designed as seismic Category II.

The purpose of cranes and hoists is to safely move material and equipment as required in order to support operations and maintenance activities. The cranes and hoists accomplish this through compliance with NUREG-0612 and the use of written procedures so damage resulting from a heavy load drop will not prevent safe shutdown of the reactor.

LRA Table 2.3.3-8 identifies the components subject to an AMR for the cranes and hoists by component type and intended function.

2.3.3.8.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the cranes and hoists mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.9 Equipment and Floor Drainage System

2.3.3.9.1 Summary of Technical Information in the Application

LRA Section 2.3.3.9 describes the equipment and floor drainage system, which is a normally operating mechanical system designed to collect and transfer radioactive and nonradioactive liquid waste for processing or discharge to the cooling tower basin or the Delaware River.

The purpose of the equipment and floor drainage system is to collect plant effluents and transfer them for appropriate processing or discharge to the cooling tower basin or the Delaware River.

The equipment and floor drainage system accomplishes this purpose through the use of gravity drain lines, sumps, and pumps used to separate waste discharge based on the source point of discharge. The equipment and floor drainage system is designed to accommodate the volumes of fluids resulting from maintenance activities, system flushing, rinsing operations, and other plant work and is sized to minimize the potential for plant flooding.

LRA Table 2.3.3-9 identifies the components subject to an AMR for the equipment and floor drainage system by component type and intended function.

2.3.3.9.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the equipment and floor drainage system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the equipment and floor drains subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.10 Fire Protection System

2.3.3.10.1 Summary of Technical Information in the Application

LRA Section 2.3.3.10 describes the fire protection system, which is a normally operating mechanical system designed to provide for the rapid detection and suppression of a fire at the plant.

The purpose of the fire protection system is to prevent fires from starting, promptly detect and suppress fires to limit damage, and in the event of a fire allow for safe shutdown to occur. The fire protection system accomplishes this purpose by providing fire protection equipment in the form of detectors, alarms, fire barriers, and suppression for selected areas of the plant.

The fire protection system consists of the fire protection water systems, carbon dioxide (CO_2) systems, Halon system, foam system, portable fire extinguishers, and fire detection and signaling systems. These systems work in conjunction with the design of the physical plant design features to provide for overall protection for HCGS. The physical plant features consist of fire barriers, fire doors, and fire rated enclosures. LRA Table 2.3.3-10 identifies the components subject to an AMR for the fire protection system by component type and intended function.

2.3.3.10.2 Staff Evaluation

The staff reviewed the license renewal drawings; Section 9.5.1, “Fire Protection Program,” of the UFSAR; and the fire protection CLB documents listed in NUREG-1048, “Safety Evaluation Report related to the operation of Hope Creek Generating Station,” dated October 1984, and NUREG-1048, Supplement Nos. 1 through 6.

During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant had not omitted from the scope of license renewal any components with intended functions required by 10 CFR 54.4(a). The staff then reviewed those components that the applicant has identified as within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff’s review of LRA Section 2.3.3.10 identified areas in which additional information was necessary to complete the review of the applicant’s scoping and screening results.

In a letter dated March 22, 2010, the staff issued RAI 2.3.3.10-1 and stated that LRA drawing LR-M-22-0, sheet 1 showed the following fire protection system components as out of scope (i.e., not colored in green on the license renewal drawing): the deep well water pumps and associated components to fire water storage tanks OAT508 and OBT508.

The staff requested that the applicant verify whether the deep well water pumps and associated components to fire water storage tanks OAT508 and OBT508 are within the scope of license renewal in accordance with 10 CFR 54.4(a) and whether they are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff further requested that, if these components are excluded from the scope of license renewal and are not subject to an AMR, the applicant provide justification for the exclusion.

In a letter dated April 6, 2010, the applicant responded to RAI 2.3.3.10-1 and stated that the fire water storage tanks (OAT508, OBT508) provide separate sources of water to the electric motor driven and diesel engine driven fire pumps. The fire water storage tanks and their associated components (colored green on license renewal boundary drawing LR-M-22-0, sheet 1) are within the scope of license renewal and subject to an AMR. The deep well water pumps and associated demineralized water system piping and components are not required to function in the event of a fire. These components do not provide structural support for safety-related components and do not have the potential for spatial interaction because they are not located in an area containing safety-related components. The deep well water pumps and associated demineralized water system piping and components (colored black on license renewal boundary drawing LR-M-22-0, sheet 1) are not within the scope of license renewal and are not subject to an AMR.

The staff reviewed the applicant’s response to RAI 2.3.3.10-1. The staff verified that fire water storage tanks OAT508, OBT508, and associated components are colored in green on LR-M-22-0, sheet 1 and are, therefore, within the scope of license renewal and subject to an AMR.

The staff also reviewed the applicant’s response to RAI 2.3.3.10-1 regarding the deep well water pumps. The staff found that, since the deep well water pumps are not required to function in the event of a fire, they are not within the scope of license renewal and are not subject to an AMR. Based on its review, the staff finds the applicant’s response to RAI 2.3.3.10-1 acceptable.

In a letter dated March 22, 2010, the staff issued RAI 2.3.3.10-2 and requested that the applicant determine whether LRA Tables 2.3.3-10 and 3.3.2-10 should include the following fire protection components:

- hose racks
- passive components in diesel engines for fire water pumps
- fire retardant coating for structural steel
- sight glasses (foam storage tank)
- spray nozzles (iodine removal filter)

If the applicant determined that LRA Tables 2.3.3-10 and 3.3.2-10 should not include these components, the staff requested that the applicant provide justification for the exclusion of these components from the scope of license renewal.

In a letter dated April 6, 2010, the applicant responded to RAI 2.3.3.10-2 in regards to the hose racks and stated:

> Hose rack assemblies consist of valves, piping and fittings. These components are included in the "Valve Body" and "Piping and Fittings" component type in LRA Tables 2.3.3-10 and 3.3.2-10. Fire hoses are evaluated as consumables, as described in LRA Section 2.1.6.4. Fire hoses are periodically inspected in accordance with NFPA standards and replaced as required, and are therefore not long-lived and not subject to an AMR.

The staff verified that LRA Tables 2.3.3-10 and 3.3.2-10 list valve body and piping and fittings. Based on its review, the staff finds the applicant's response to this portion of RAI 2.3.3.10-2 acceptable.

In a letter dated April 6, 2010, the applicant responded to RAI 2.3.3.10-2 with regard to the passive components in diesel engines for fire water pumps and stated that the diesel driven fire water pump and diesel engine driver are mounted together on the vendor supplied equipment base plate, which is anchored and grouted to the fire water pump house foundation slab. These equipment supports and supporting structural components are subject to an AMR and are included in the applicable tables in the LRA Sections 2.4 and 3.5. The diesel engine and its components are part of the active engine and are not subject to an AMR. In its response, the applicant stated:

> The piping and components that provide the external cooling water to and from the diesel engine are included in LRA Tables 2.3.3-10 and 3.3.2-10. The component types are Piping and Fittings, Strainer Body and Valve Body.
>
> Fuel oil components that are not part of the active diesel engine assembly are included in LRA Tables 2.3.3-10 and 3.3.2-10. This includes the outdoor fuel oil storage tank, the fuel inlet and return piping and components from the tank up to and including the flexible metal hose connections to the diesel engine assembly. The fuel oil prefilter mounted on the engine assembly is also included in LRA Tables 2.3.3-10 and 3.3.2-10. The component types are Filter Housing, Hoses, Piping and Fittings and Valve Body.
>
> It was discovered that the flexible metal hose components were inadvertently identified with an Air – Outdoor environment. These hoses are located indoor.

Table 3.3.2-10 Component Type "Hoses" (LRA page 3.3-181) is revised as follows:

Table 3.3.2-10 Fire Protection System

(Changes are highlighted with bold for inserted text and strikethroughs for deleted text.)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Hoses	Pressure Boundary	Copper Alloy with less than 15% Zinc	~~Air – Outdoor (External)~~ **Air – Indoor (External)**	~~Loss of Material/Pitting and Crevice Corrosion~~ **None**	~~Fire Protection~~ **None**	**V.F-3**	**3.2.1-53**	~~G, 11~~ **A**

In its April 6, 2010, response to RAI 2.3.3.10-2, the applicant stated that the passive components in diesel engines for fire water pumps are included in LRA Tables 2.3.3-10 and 3.3.2-10 under the following passive component types as appropriate: Filter Housing, Hoses Piping and Fittings, Strainer Body and Valve Body. These passive components include: (1) the piping and components that provide the external cooling water to and from the diesel engine, (2) the outdoor fuel oil storage tank, (3) the fuel inlet and return piping and components from the tank up to and including the flexible metal hose connections to the diesel engine assembly, and (4) the fuel oil prefilter mounted on the engine assembly.

The staff reviewed the applicant's response and confirmed that the passive components in diesel engines for fire water pumps listed by the applicant are included in LRA Tables 2.3.3-10 and 3.3.2-10. Active components that are part of the diesel engine assembly are in the scope of license renewal but are not subject to an AMR Based on its review, the staff found the applicant's response to this portion of RAI 2.3.3.10-2 acceptable.

The staff notes that the applicant, during its review of RAI 2.3.3.10-2, identified the following error in its LRA: Table 3.3.2-10 showed the environment for flexible metal hoses as "Air – Outdoor." The applicant revised LRA Table 3.3.2-10 to show the environment for these hoses as "Air – Indoor." The staff concurs with this correction.

In a letter dated April 6, 2010, the applicant responded to RAI 2.3.3.10-2 with regards to fire retardant coating for structural steel and stated:

> Fire retardant coatings are present on structural steel in various buildings at Hope Creek, including the reactor, auxiliary and turbine buildings. These coatings are in scope for license renewal and are subject to an AMR. Table 2.3.3-10 (LRA page 2.3-141) is revised to add the component type Fire Barriers (Fire Retardant Coating for Structural Steel) as follows:

Table 2.3.3-10 Fire Protection System

Components Subject to Aging Management Review

Component Type	Intended Function
Fire Barriers (Fire Retardant Coating for Structural Steel)	**Fire Barrier**

Table 3.3.2-10 (LRA page 3.3-177) is revised to add the component type Fire Barriers (Fire Retardant Coating for Structural Steel) as follows:

Table 3.3.2-10 Fire Protection System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Fire Barrier (Fire Retardant Coating for Structural Steel)	Fire Barrier	Cementitious Fire Proofing	Air – Indoor	Loss of Material/ Cracking	Fire Protection			F, 19

Table 3.3.2-10 Plant Specific Notes (LRA Page 3.3-196) is revised to add note 19, as follows:

19. Based on industry standards and guidelines, cementitious fireproofing is susceptible to loss of material/cracking in this environment. This aging effect will be monitored and managed with the fire protection program.

In its April 6, 2010, response to RAI 2.3.3.10-2, the applicant stated that fire retardant coatings for structural steel are within the scope of license renewal and subject to an AMR. The applicant revised LRA Tables 2.3.3-10 and 3.3.2-10 to add fire retardant coatings for structural steel as a fire barrier that is within the scope of license renewal and subject to an AMR and added Note 19 to LRA Table 3.3.2-10. This note justifies the inclusion of fire retardant coating for structural steel in the Fire Protection Program. Therefore, the staff finds the applicant's response to this portion of RAI 2.3.3.10-2 acceptable.

In a letter dated April 6, 2010, the applicant responded to RAI 2.3.3.10-2 with regards to sight glasses (foam storage tank) and stated:

> A foam fire suppression system is provided for the fuel oil storage tank, as shown on boundary drawing LR-M-22-0, Sheet 6. In the original design, foam was supplied from a foam storage tank and associated piping and components, including a tank site glass, located in the Fuel Oil Foam House. This foam supply system has been removed from service, disconnected and replaced by an onsite portable foam supply. The sight glass has also been removed from service, and is therefore not in the scope of license renewal and not subject to an AMR.

In its April 6, 2010, response to RAI 2.3.3.10-2, the applicant stated that the foam storage tank is no longer in use and that, therefore, the sight glass located on the foam storage tank is not within the scope of license renewal and is not subject to an AMR. Therefore, the staff finds the applicant's response to this portion of RAI 2.3.3.10-2 acceptable.

In a letter dated April 6, 2010, the applicant responded to RAI 2.3.3.10-2 with regards to the spray nozzles (iodine removal filter) and stated:

> Fire protection water spray systems are installed for ventilation systems that contain charcoal adsorber beds for iodine removal. These ventilation systems and associated charcoal filter units are identified below:
>
> - control room emergency filter units (AVH400, BVH400)

- technical support center (TSC) emergency filter unit (0VH313)
- filtration, recirculation and ventilation system (FRVS) recirculation units (AVH213, BVH213, CVH213, DVH213, EVH213, FVH213)
- FRVS ventilation filter units (AVH206, BVH206)
- containment prepurge filter unit (0VH200)
- radwaste tank filter units (AVH306, BVH306)

The fire protection spray systems associated with these filter units are identified on Boundary Drawing LR-M-22-0, Sheet 3, as 1D1, 1D2, 1PD3, 1PD4, 1PD5, 1PD6, 1PD7, 1PD8, 1PD9, 1PD10, 1PD11, 0D3, 0D4 and 0D5.

The Control Room Emergency Filter Units (AVH400, BVH400) and TSC Emergency Filter Unit (0VH313) charcoal adsorber bed deluge is accomplished by flooding the associated charcoal bed through stainless steel distribution piping located within the filter unit housing. Fire suppression water is discharged to the charcoal bed through holes drilled in the distribution piping at appropriate locations to flood the bed. Spray nozzles are not used in these units. The distribution piping located inside the HVAC filter unit is evaluated with Piping and Fittings for an AMR in the Fire Protection System, shown on LRA Tables 2.3.3-10 and 3.3.2-10.

It was discovered that the Control Room and Control Area HVAC System incorrectly identified spray nozzles associated with the charcoal bed fire suppression system Tables 2.3.3-7 and 3.3.2-7. Table 2.3.3-7 (LRA page 2.3-125) is revised to delete the component type Nozzle as follows:

Table 2.3.3-7 Control Room and Control Area HVAC Systems

Components Subject to Aging Management Review

(Changes are highlighted with strikethroughs for deleted text.**)**

Component Type	Intended Function
~~Nozzle~~	~~Spray~~

Table 3.3.2-7 (LRA page 3.3-162) is revised to delete the component type Nozzle as follows:

Table 3.3.2-7 Control Room and Control Area HVAC Systems

(Changes are highlighted with strikethroughs for deleted text.)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
~~Nozzle~~	~~Spray~~	~~Copper Alloy with 15% Zinc or More~~	~~Air/Gas – Wetted (External)~~	~~Loss of Material/Pitting and Crevice Corrosion~~	~~Periodic Inspection~~	~~VII.F1-16~~	~~3.3.1-25~~	~~E, 2, 5~~
~~Nozzle~~	~~Spray~~	~~Copper Alloy with 15% Zinc or More~~	~~Air/Gas – Wetted (Internal)~~	~~Loss of Material/Pitting and Crevice Corrosion~~	~~Periodic Inspection~~	~~VII.F1-16~~	~~3.3.1-25~~	~~E, 2~~

Boundary Drawing LR-M-89-1, Sheet 1, Note 5, is replaced with the following:

> 5. Charcoal deluge spray piping consists of water distribution piping with drilled holes to flood the carbon beds, and is evaluated as Piping and Fittings with the Fire Protection System for an AMR.

The Filtration, Recirculation and Ventilation System (FRVS) Recirculation Units (AVH213, BVH213, CVH213, DVH213, EVH213, FVH213) charcoal adsorber bed deluge arrangement is the same as the Control Room and Control Area HVAC System described above. Charcoal adsorber bed fire suppression is accomplished by flooding the associated charcoal bed through stainless steel distribution piping located within the filter unit housing. Fire suppression water is discharged to the charcoal bed through holes drilled in the distribution piping at appropriate locations to flood the bed. Spray nozzles are not used in these units. The distribution piping located inside the HVAC filter unit is evaluated with Piping and Fittings for an AMR in the Fire Protection System, shown on LRA Tables 2.3.3-10 and 3.3.2-10.

It was discovered that Boundary Drawing LR-M-83-1, Sheet 1, Note 8, incorrectly describes the charcoal bed deluge as having spray nozzles. This note is replaced with the following:

> 8. Charcoal deluge spray piping consists of water distribution piping with drilled holes to flood the carbon beds, and is evaluated as Piping and Fittings with the Fire Protection System for an AMR.

The FRVS Ventilation Filter Units (AVH206, BVH206), Containment Prepurge Filter Unit (0VH200) and Radwaste Tank Filter Units (AVH306, BVH306) charcoal adsorber bed deluge is accomplished by spraying the associated charcoal bed through galvanized steel distribution piping and brass spray nozzles located within the filter unit housing. Fire suppression water is discharged to the charcoal bed through the spray nozzles at appropriate locations to cool the bed. The distribution piping and spray nozzles are evaluated for an AMR in the Fire Protection System. These charcoal bed spray nozzles were inadvertently omitted from LRA Tables 2.3.3-10 and 3.3.2-10. Table 2.3.3-10 (LRA page 2.3-141) is revised to include component type Spray Nozzles (Charcoal Filter) as follows:

Table 2.3.3-10 Fire Protection System

Components Subject to Aging Management Review

Component Type	Intended Function
Spray Nozzles (Charcoal Filter)	Spray

Table 3.3.2-10 (LRA page 3.3-187) is revised to include component type Spray Nozzles (Charcoal Filter) as follows:

Table 3.3.2-10 Fire Protection System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Spray Nozzles (Charcoal Filter)	Spray	Copper Alloy with 15% Zinc or More	Air - Indoor (External)	None	None	V.F-3	3.2.1-53	A
Spray Nozzles (Charcoal Filter)	Spray	Copper Alloy with 15% Zinc or More	Air - Indoor (Internal)	None	None	V.F-3	3.2.1-53	A

Based on its review and the addition of spray nozzles to LRA Tables 2.3.3-10 and 3.3.2-10, the staff finds the applicant’s response to this portion of RAI 2.3.3.10-2 acceptable.

The staff notes that the applicant, during its review of RAI 2.3.3.10-2, identified and corrected some errors in its LRA as follows: spray nozzles are not used in the fire protection spray systems associated with iodine removal filter units in the control room and control area HVAC systems. The applicant deleted “Nozzle” from the column “Component Type” under “Control Room and Control Area HVAC Systems” in LRA Tables 2.3.3-7 and 3.3.2-7. The applicant also replaced drawing notes that incorrectly described the charcoal bed deluge systems as having spray nozzles.

In a letter dated March 22, 2010, the staff issued RAI 2.3.3.10-3 and requested that the applicant verify whether the Halon 1301 total flooding fire suppression systems located in the quality assurance vault in the administration building and underneath the raised floor of room 1 in the guardhouse are within the scope of license renewal in accordance with 10 CFR 54.4(a) and whether they are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff further requested that, if they are excluded from the scope of license renewal and not subject to an AMR, the applicant provide justification for the exclusion.

In a letter dated April 6, 2010, the applicant responded to RAI 2.3.3.10-3 and stated that the Halon total flooding fire suppression system in the quality assurance vault in the administrative building and the Halon total flooding fire suppression system underneath the raised floor of room 1 in the guardhouse are not within the scope of license renewal in accordance with 10 CFR 54.4(a) and are not subject to an AMR in accordance with 10 CFR 54.21(a)(1). These systems are not safety-related, and failure of these systems cannot prevent accomplishment of safety-related functions. These systems are not credited to demonstrate compliance with any of the regulated events in accordance with 10 CFR 54.4(a)(3). Therefore, these systems do not have any intended functions for license renewal and are not within scope.

The staff reviewed the applicant's response to RAI 2.3.3.10-3. Since the room in the administration building called the quality assurance vault is no longer used as a quality assurance vault, the Halon total flooding fire suppression system in that room is not required to protect safety-related SSCs and is, therefore, not within the scope of license renewal and not subject to an AMR. Since the Halon total flooding fire suppression system in the guardhouse is not required to protect safety-related SSCs, it is not within the scope of license renewal and not subject to an AMR. Based on its review, the staff finds the applicant's response to RAI 2.3.3.10-3 acceptable.

In a letter dated March 22, 2010, the staff issued RAI 2.3.3.10-4 and quoted the following excerpts from Section 9.5.1.4 of NUREG-1048, Supplement No. 5, "…the staff also questioned the fire rating of certain panels used in the control rooms. The applicant provided the staff with a letter from the manufacturer certifying that these panels were fabricated from the same type of materials and in a configuration used in 3-hour-rated fire doors…"

The staff requested that the applicant verify whether the panels are within the scope of license renewal in accordance with 10 CFR 54.4(a) and whether they are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff further requested that, if they are excluded from the scope of license renewal and not subject to an AMR, the applicant provide justification for the exclusion.

In a letter dated April 6, 2010, the applicant responded to RAI 2.3.3.10-4 and stated:

> Panels are installed in control room walls. Additionally, the wall in the control room viewing area has a … glass window.
>
> Steel wall panels and [the glass] window are in the scope of License Renewal and are subject to AMR. Review of Table 3.3.2-10 of the Hope Creek LRA determined that the steel and glass fire barrier materials were inadvertently omitted from this table. Table 3.3.2-10 is revised to add these materials to the existing component type Fire Barrier (Walls, Ceilings, and Floors) as shown below:

Table 3.3.2-10 Fire Protection System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol.2 Item	Table 1 Item	Notes
Fire Barrier (Walls, Ceilings and Floors)	Fire Barrier	Carbon Steel	Air – Indoor	Loss of Material/ corrosion	Fire Protection			F.11
Fire Barrier (Walls, Ceilings and Floors)	Fire Barrier	Glass	Air – Indoor	None	None	VII.J-8	3.3.1-93	C

> Additionally, LRA Section 3.3.2.1.10, Fire Protection System, is revised to include glass material.

The staff reviewed the applicant's response to RAI 2.3.3.10-4. The addition of steel and glass fire barrier materials to LRA Table 3.3.2-10 confirms that the steel wall panels and glass window located in the control room are within the scope of license renewal and are subject to an AMR. Based on its review, the staff finds the applicant's response to RAI 2.3.3.10-4 acceptable.

In its letter dated March 22, 2010, the staff issued RAI 2.3.3.10-5 and quoted the following excerpt from Section 9.5.1.4 of NUREG-1048, Supplement No. 5, "In the SER the staff identified 12 locations were the applicant committed to install automatic sprinkler systems to protect areas containing high concentrations of cables and cable trays…"

The staff requested that the applicant verify whether these automatic sprinkler systems are within the scope of license renewal in accordance with 10 CFR 54.4(a) and whether they are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff further requested that, if they are excluded from the scope of license renewal and not subject to an AMR, the applicant provide justification for the exclusion.

In a letter dated April 6, 2010, the applicant responded to RAI 2.3.3.10-5 and stated:

> The automatic preaction sprinkler systems described in NUREG-1048, Supplement No. 5, Section 9.5.1.4, "General Plant Guidelines," have been installed and are described in the Hope Creek UFSAR Section 9.5.1.1.14. These automatic sprinkler systems are included in the scope of license renewal in accordance with 10 CFR 54.4(a) and subject to an AMR in accordance with 10 CFR 54.21(a)(1). These preaction sprinkler systems are designated as 1PS6, 1PS7, 1PS8, 1PS9, 1PS10, 1PS11, 1PS12, 1PS13, 1PS14, 1PS15 and 1PS16, and are shown as in scope on license renewal boundary drawing LR-M-22-0, sheet 3. The typical detail for these systems is Detail V, shown on license renewal boundary drawing LR-M-22-0, sheet 6.

The staff reviewed the applicant's response to RAI 2.3.3.10-5 which confirmed that the automatic sprinklers had been installed and that they were included within the scope of license renewal and subject to an AMR. However, the staff noticed that the applicant, in its response to RAI 2.3.3.10-5, had listed only 11 preaction sprinkler systems while Section 9.5.1.4 of NUREG-1048, Supplement No. 5 stated that the applicant committed to install automatic sprinkler systems in 12 locations. The staff requested a clarification for the discrepancy with the number of sprinkler systems. In a telephone conference call held on April 14, 2010, the applicant clarified the discrepancy as follows: the number of automatic sprinkler systems in the UFSAR (10 sprinklers systems); in NUREG-1048, Supplement No. 5 (12 sprinklers); and in the applicant's response to RAI 2.3.3.10-5 (11 sprinklers systems) are different because of the difference in grouping these automatic sprinkler systems by fire area or by room. Based on its review and on the clarification received during the April 4, 2010, conference call that there are actually 11 sprinkler systems that are located so as to cover 14 areas (3 grouped pairs), the staff finds the applicant's response to RAI 2.3.3.10-5 acceptable.

2.3.3.10.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the fire protection system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.11 Fire Pump House Ventilation System

2.3.3.11.1 Summary of Technical Information in the Application

LRA Section 2.3.3.11 describes the fire pump house ventilation system, which is an automatic air ventilation system designed to supply sufficient combustion air for the diesel driven fire pump engine. It is also designed to maintain the fire water pump house room air flow and temperature in the building compartments within an acceptable range by the use of louvers, heaters, and roof exhaust fans.

The purpose of the fire pump house ventilation system is to supply sufficient combustion air for the diesel fire pump. In addition, it maintains building room air temperature above freezing and will limit the rise of room temperature during the summer and maintain the equipment environment within the design temperature limits. The fire pump house ventilation system accomplishes this by using ventilation louvers, electric unit heaters, exhaust fans, and associated controls.

2.3.3.11.2 LRA Table 2.3.3-11 identifies the components subject to an AMR for the fire pump house ventilation system by component type and intended function.Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the fire pump house ventilation system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.12 Fresh Water Supply System

2.3.3.12.1 Summary of Technical Information in the Application

LRA Section 2.3.3.12 describes the fresh water supply system, which is a normally operating mechanical system designed to send fresh water and domestic water to plumbing fixtures, laundry rooms, safety showers, eye washes, and washing stations.

The purpose of the fresh water supply system is to supply water in sufficient quantities to satisfy the demand for station potable and makeup water, safety showers, eye washes, and sanitary water. The fresh water supply system accomplishes this by using wells, pumps, piping, piping components, plumbing fixtures, tanks, and valves.

LRA Table 2.3.3-12 identifies the components subject to an AMR for the fresh water supply system by component type and intended function.

2.3.3.12.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings as described in Section 2.3, the staff concludes that the applicant has appropriately identified the fresh water supply system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.13 Fuel Handling and Storage System

2.3.3.13.1 Summary of Technical Information in the Application

LRA Section 2.3.3.13 describes the fuel handling and storage system, which consists of the spent fuel storage pool and racks, new fuel storage vault and racks, cask loading pit and spent fuel cask, and fuel handling equipment.

The purpose of the fuel handling and storage system is to support, transfer, and provide for storage of nuclear fuel in a manner that precludes inadvertent criticality and maintains shielding and cooling of spent fuel. The fuel handling and storage system accomplishes this through the spent fuel storage rack design. The spent fuel storage racks are designed to maintain fuel in a subcritical configuration having a k_{eff} less than or equal to 0.95. To preclude the possibility of raising spent fuel assemblies out of the water, the hoist incorporates redundant electrical limit switches and interlocks that prevent hoisting above the preset limit. In addition, the cables on the auxiliary hoist incorporate adjustable mechanical stops that jam the hoist cable against the hoist structure, which prevents further hoisting, if the limit switch interlock system fails.

LRA Table 2.3.3-13 identifies the components subject to an AMR for the fuel handling and storage system by component type and intended function.

2.3.3.13.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the fuel handling and storage system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.14 Fuel Pool Cooling and Cleanup System

2.3.3.14.1 Summary of Technical Information in the Application

LRA Section 2.3.3.14 describes the fuel pool cooling and cleanup system, which is a normally operating closed-loop system designed to remove heat from the fuel storage pool and maintain fuel storage pool water clarity.

The purpose of the fuel pool cooling and cleanup system is to remove decay heat from the spent fuel assemblies that are stored within the fuel storage pool during all modes of operation, to remove decay heat from the water inventory contained within the reactor well and dryer-separator storage pool during refueling outages, to minimize thermal stresses within the floor and walls of the fuel storage pool, and maintain the chemistry of the fuel storage pool water inventory within acceptable EPRI guidelines.

The fuel pool cooling and cleanup system accomplishes this by delivering recirculating water from the fuel pool during normal operation as well as from the reactor well, fuel cask storage pit, and dryer-separator storage pool during refueling outages, which is pumped through the fuel pool cooling and cleanup system heat exchangers and filter-demineralizer system. The fuel pool cooling and cleanup system heat exchangers then remove heat from the pools and transfer it to the closed-cycle cooling water system. The filter-demineralizer system maintains pool water purity and clarity by a combination of filtration and ion exchange.

The fuel pool cooling and cleanup system operation is a manually initiated system for spent fuel and cooling and cleanup functions.

LRA Table 2.3.3-14 identifies the components subject to an AMR for the fuel pool cooling and cleanup system by component type and intended function.

2.3.3.14.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.14, UFSAR Section 9.1.3, and the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results.

In a letter dated April 15, 2010, the staff issued RAI 2.3.3.14-01 and noted that license renewal drawing LR-M-53-1, sheet 1, locations B-7 and B-8, shows starter strainers (TS 182 and TS 181) in 10 CFR 54.4(a)(1) lines 8"-HBC-042 and 8"-HBC-047, respectively, that are not included as a component type in LRA Table 2.3.3-14. The applicant was requested to provide additional information to explain why these in-scope strainers are not included as a component type with their intended function in LRA Table 2.3.3-14.

In a letter dated April 15, 2010, the staff issued RAI 2.3.3.14-02 and noted that license renewal drawing LR-M-53-1, sheet 1 shows 13 locations of 10 CFR 54.4(a)(2) pipelines connected to 10 CFR 54.4(a)(1) pipelines. The applicant was requested to provide additional information to locate the anchors for the pipelines between the end of the (a)(2) scoping boundary and the safety-nonsafety interfaces.

The applicant's response, dated May 11, 2010, described the location of the anchors, which are within the existing (a)(2) scoping boundary. This conforms to the applicant's methodology and did not result in the inclusion of any additional components within the scope of license renewal. Therefore, the staff's concerns described in RAI 2.2.3.14-01 and RAI 2.3.3.14-02 are resolved.

2.3.3.14.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the fuel pool cooling and cleanup system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.15 Hardened Torus and Vent System

2.3.3.15.1 Summary of Technical Information in the Application

LRA Section 2.3.3.15 describes the hardened torus and vent system, which is a hard-piped vent system designed for the mitigation of severe accident sequences that are beyond the DBAs in which decay heat removal capability is unavailable.

The purpose of the hardened torus and vent system is to vent the primary containment from the torus during severe accident sequences that involve loss of normal decay heat removal capability. The hardened torus and vent system accomplishes this by providing a vent path from the torus to the environment through the containment prepurge cleanup system return header from the torus. The hardened torus vent system is only used for conditions beyond the DBEs. LRA Table 2.3.3-15 identifies the components subject to an AMR for the hardened torus and vent system by component type and intended function.

2.3.3.15.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the hardened torus vent system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.16 Hydrogen Water Chemistry System

2.3.3.16.1 Summary of Technical Information in the Application

LRA Section 2.3.3.16 describes the hydrogen water chemistry system, which is designed to inject hydrogen at the suction of the secondary condensate pumps to lower recirculation and reactor water oxygen concentration, and inject oxygen at the suction of the primary condensate pumps to increase oxygen concentration in the condensate and feedwater to reduce flow-assisted corrosion.

The purpose of the hydrogen water chemistry system is to reduce the potential for intergranular stress-corrosion cracking (IGSCC) and flow-assisted corrosion. It accomplishes this by injecting hydrogen to reduce the potential for IGSCC, injecting oxygen to reduce flow-assisted corrosion, and monitoring for the concentration of dissolved hydrogen and oxygen in the reactor recirculation system.

The addition of hydrogen reduces the oxygen content in the reactor water and reduces the corrosion potential of the water. Although the hydrogen concentration is reduced in the steam, the hydrogen/oxygen ratio increases. To ensure that sufficient oxygen is present in the gaseous radwaste system to combine with the excess hydrogen, air is injected upstream of the off-gas recombiners to maintain the stoichiometric balance of oxygen and hydrogen. In order to maintain the desired dissolved oxygen level in the feedwater, a supplemental oxygen injection system (oxygen gas bottles) is also installed to inject oxygen, on an as needed basis, upstream of the primary condensate pumps.

LRA Table 2.3.3-16 identifies the components subject to an AMR for the hydrogen water chemistry system by component type and intended function.

2.3.3.16.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the hydrogen water chemistry system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.17 Leak Detection and Radiation Monitoring System

2.3.3.17.1 Summary of Technical Information in the Application

LRA Section 2.3.3.17 describes the leak detection and radiation monitoring system, which is a normally operating instrumentation system that detects leaks from the reactor coolant pressure boundary and other plant systems, and assesses overall plant radiological conditions at the facility. In addition, this system also detects the radiation level and the release of radioactivity in key locations throughout the plant. The leak detection and radiation monitoring system consists of the following two plant systems: leak detection plant system and radiation monitoring plant system.

The purpose of the leak detection plant system is to detect leaks and provide alarms at established leakage rate limits so that the affected system can be isolated if necessary. To accomplish this, the system directly monitors the drywell for reactor coolant pressure boundary leakage as required by RG 1.45, and indirectly detects leakage from the reactor coolant pressure boundary and from other systems by monitoring the process variables.

The purpose of the radiation monitoring plant system is to detect the release of radioactivity, monitor radiation levels, and provide alarms so that the general public and plant personnel can be protected from exposure in excess of those allowed by the applicable regulations. The system accomplishes this by using radiation detector and associated instrumentation to monitor and indicate the radiation levels.

LRA Table 2.3.3-17 identifies the components subject to an AMR for the leak detection and radiation monitoring system by component type and intended function.

2.3.3.17.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the leak detection and radiation monitoring system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.18 Makeup Demineralizer System

2.3.3.18.1 Summary of Technical Information in the Application

LRA Section 2.3.3.18 describes the makeup demineralizer system, which is a normally operating mechanical system.

The purpose of the makeup demineralizer is to demineralize fresh water from the station wells, store the demineralized water, and deliver it to plant services, as required. The makeup demineralizer accomplishes this purpose by pumping fresh water through trains, consisting of a cation exchanger, an anion exchanger, and a mixed bed exchanger. The resulting effluent through the trains is demineralized water.

LRA Table 2.3.3-18 identifies the components subject to an AMR for the makeup demineralizer system by component type and intended function.

2.3.3.18.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.18, UFSAR Section 9.2.3, and the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results.

In a letter dated April 15, 2010, the staff issued RAI 2.3.3.18-01 and noted that license renewal drawing LR-M-11-1, sheet 1 shows two 10 CFR 54.4(a)(1) lines (2"-HCC-111 and 2"-HCC-112) continue to 10 CFR 54(a)(2) lines AN-2"-HCD-001. The applicant was requested to provide additional information to locate the anchor for the two AN-2"-HCD-001 lines between the end of the (a)(2) scoping boundary and the safety-nonsafety interface.

In a letter dated April 15, 2010, the staff issued RAI 2.3.3.18-02 and noted that license renewal drawing LR-M-90-1, sheet 3, locations D-6 and E-6, shows 10 CFR 54.4(a)(1) lines 18"-HCC-187, 18"-HCC-188, and 18"-HCC-189 continue to 10 CFR 54.4(a)(2) lines 2"-HCD-022, 2"-HBD-133, and 2"-HBD-132. License renewal drawing LR-M-90-1, sheet 2, location D-6, shows 10 CFR 54.4(a)(1) head tank BT 410 connected to 10 CFR 54(a)(2) line 2"-HCD-024. The applicant was requested to provide additional information to locate the anchors for these lines.

In a letter dated April 15, 2010, the staff issued RAI 2.3.3.18-03 and noted that license renewal drawing LR-30-1, sheet 2, locations G-2, G-3, G-5, and G-7, shows 10 CFR 54.4(a)(1) lines 1"-HBC-098, 1"-HBC-096, 1"-HBC-097, and 1"-HBC-095 continue to 10 CFR 54.4(a)(2) lines 1"-HCD-232, 1"-HCD-230, 1"-HCD-231, and 1"-HCD-229. The applicant was requested to provide additional information to locate the anchors for these lines.

The applicant's response, dated May 11, 2010, described the location of the anchors, which are within the existing (a)(2) scoping boundary. This conforms to the applicant's methodology and did not result in the inclusion of any additional components within the scope of license renewal.

Based on its review, the staff finds the applicant's responses to RAI 2.3.3.18-01, RAI 2.3.3.18-02, and RAI 2.3.3.18-03 acceptable because the applicant provided the location of the seismic anchors for the lines in question. Therefore, the staff's concerns described in RAI 2.3.3.18-01, RAI 2.3.3.18-02, and RAI 2.3.3.18-03 are resolved.

2.3.3.18.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, The applicant's RAI responses, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the makeup demineralizer system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.19 Primary Containment Instrument Gas System

2.3.3.19.1 Summary of Technical Information in the Application

LRA Section 2.3.3.19 describes the primary containment instrument gas system, which is a safety-related system designed to provide a continuous supply of dried, oil-free, filtered compressed gas to pneumatic components inside the primary containment during normal operations.

The purpose of the primary containment instrument gas system is to provide clean and dried compressed gas to pneumatically-operated instruments and valves. To accomplish this, the system takes gas from inside the primary containment or reactor building, and processes the gas through intake screen, filters, gas compressors, intercoolers, aftercoolers, moisture separators, thermo-siphons, gas dryers, gas receivers, and gas headers for distribution to components in support of plant operations.

LRA Table 2.3.3-19 identifies the components subject to an AMR for the primary containment instrument gas system by component type and intended function.

2.3.3.19.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the primary containment instrument gas system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.20 Primary Containment Leakage Rate Testing System

2.3.3.20.1 Summary of Technical Information in the Application

LRA Section 2.3.3.20 describes the primary containment leakage rate testing system, which is designed to provide a means to measure the leakage from the primary containment.

The primary containment leakage rate testing system consists of the following subsystems: Type A testing subsystem, Type B testing subsystem, and Type C testing subsystem. The Type A testing subsystem is used to pressurize the primary containment to a test pressure so that the integrated leakage rate of the containment can be determined and compared with the appropriate acceptance criteria. The determination of primary containment leakage is accomplished with a data acquisition center. The Type B testing subsystem is used to pressurize and measure local leakage across pressure or leakage limiting boundaries other than valves. Similarly, the Type C testing subsystem is used to pressurize and measure local leakage rates across containment isolation valves.

LRA Table 2.3.3-20 identifies the components subject to an AMR for the primary containment leakage rate testing system by component type and intended function.

2.3.3.20.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the primary containment leakage rate testing system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.21 Process and Post-Accident Sampling Systems

2.3.3.21.1 Summary of Technical Information in the Application

LRA Section 2.3.3.21 describes the process and post-accident sampling system, which is a normally operating system that consists of the process sampling plant system and the post-accident plant sampling system.

The process sampling plant system is designed to permit a representative sample to be taken from all process streams related to plant power operation and liquid radwaste processing. The sample is in a form which can be used in the laboratory and which safeguards against change in the constituents to be examined, minimizes the contamination and radiation at the sample point, and reduces decay and sample line plateout as much as possible.

The purpose of the process sampling plant system is to monitor the operation of equipment and supply information for making operating decisions where these are influenced by water chemistry. It accomplishes this by collecting steam, gaseous, and liquid samples throughout the facility.

The post-accident plant sampling system is designed to obtain representative liquid and gas grab samples from the reactor coolant system and from the primary containment and reactor building atmospheres for radiological and chemical analysis under accident conditions.

The purpose of the post-accident plant sampling system is to permit collection and processing of liquid and gaseous samples. The post-accident plant sampling system accomplishes this by providing piping to collect these samples during normal and post-accident conditions, and a system to analyze the samples during post-accident conditions.

LRA Table 2.3.3-21 identifies the components subject to an AMR for the process and post-accident sampling system by component type and intended function.

2.3.3.21.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.21, UFSAR Section 9.3.2, and the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In a letter dated April 15, 2010, the staff issued RAI 2.3.3.21-01 and noted that license renewal drawing LR-M-38-0, sheet 1, location B-7, shows line 1"-DBB-006 within the scope of license renewal for 10 CFR 54.4(a)(1) attached to tubing that is not within scope. The applicant was requested to provide additional information to locate the anchor after the safety-nonsafety interface.

The applicant's response, dated May 11, 2010, described the location of the anchors, which are within the existing (a)(2) scoping boundary. This conforms to the applicant's methodology and did not result in the inclusion of any additional components within the scope of license renewal. Based on its review, the staff finds the applicant's response to RAI 2.3.3.21-01 acceptable

2.3.3.21.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the process and post-accident sampling system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.22 Radwaste System

2.3.3.22.1 Summary of Technical Information in the Application

LRA Section 2.3.3.22 describes the radwaste system, which is a normally operating mechanical system designed to process liquid radioactive waste for reuse by the plant or for discharge to the Delaware River. The radwaste system also processes and packages solid radioactive waste for shipment to an offsite repository.

The purpose of the radwaste system is to provide for the collection and processing of potentially radioactive liquid and solid waste generated by the plant. The radwaste system accomplishes this through the use of tanks, demineralizers, filters, coolers, piping, valves, and pumps required to process the liquid radwaste, and waste containers and drums to process solid radwaste.

LRA Table 2.3.3-22 identifies the components subject to an AMR for the radwaste system by component type and intended function.

2.3.3.22.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.22, UFSAR Sections 11.2 and 11.4, and the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In a letter dated April 15, 2010, the staff issued RAI 2.3.3.22-01 and noted that license renewal drawing LR-M-61-1, sheet 1, locations G-6 and G-7, shows a 3 inch 10 CFR 54.4(a)(1) line (3"-HBB-014) connected to 10 CFR 54.4(a)(2) lines (3"-HBD+-013 and 3"-HBD+-017). The applicant was requested to provide additional information to locate the seismic anchors or anchored components for the 3"-HBD+-013 and 3"-HBD+-017 lines between the end of the (a)(2) scoping boundary and the safety-nonsafety interface.

In a letter dated April 15, 2010, the staff issued RAI 2.3.3.22-02 and noted that license renewal drawing LR-M-61-1, sheet 2, locations G-6 and G-7, shows a 3 inch 10 CFR 54.4(a)(1) line (3"-HBB-023) connected to 10 CFR 54.4(a)(2) lines (3"-HBD+-022 and 3"-HBD+-019). The applicant was requested to provide additional information to locate the seismic anchors or anchored components for the 3"-HBD+-022 and 3"-HBD+-019 lines between the end of the (a)(2) scoping boundary and the safety-nonsafety interface.

The applicant's response, dated May 11, 2010, described the location of the anchors, which are within the existing (a)(2) scoping boundary. This conforms to the applicant's methodology and did not result in the inclusion of any additional components within the scope of license renewal. Based upon its review, the staff finds the applicant's responses to RAI 2.3.22-01 and RAI 2.3.22-02 acceptable. Therefore, the staff's concerns described in RAI 2.3.22-01 and RAI 2.3.22-02 are resolved.

2.3.3.22.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, The applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the radwaste system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.23 Reactor Building Ventilation System

2.3.3.23.1 Summary of Technical Information in the Application

LRA Section 2.3.3.23 describes the reactor building ventilation system, which is a continuously operating mechanical system with containment prepurge capability, heating and cooling capability, and an isolation mode. The system is designed to provide filtering, cooling, and heating to the reactor building compartments during startup, full power, shutdown, and for some portions during DBAs.

The purpose of the reactor building ventilation system is to maintain compartment temperatures at acceptable limits; it regulates the static pressure within the reactor building to maintain air flow from areas of lesser contamination to areas of greater contamination, and provides for safe disposal of airborne contaminants. The reactor building ventilation system accomplishes this by maintaining the reactor building pressure at a slightly negative pressure with respect to outdoor pressure while ventilating the reactor building with filtered air and exhausting outdoors through a high-efficiency particulate air (HEPA) filter.

LRA Table 2.3.3-23 identifies the components subject to an AMR for the reactor building ventilation system by component type and intended function.

2.3.3.23.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the reactor building ventilation system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.24 Reactor Water Cleanup System

2.3.3.24.1 Summary of Technical Information in the Application

LRA Section 2.3.3.24 describes the reactor water cleanup system, which is a filtration and demineralization system that maintains the purity of the water in the reactor coolant system. The system can be operated during startup, shutdown, and refueling modes, as well as during power operation.

The primary purpose of the reactor water cleanup system is to: (1) reduce the deposition of water impurities on fuel surfaces, thus minimizing heat transfer surface fouling; (2) reduce secondary sources of beta and gamma radiation by removing corrosion products, impurities, and fission products from the reactor coolant; (3) reduce the concentration of chloride ions to protect steel components from chloride stress corrosion; and (4) maintain or lower water level in the reactor vessel during startup, shutdown, and refueling operations, in order to accommodate reactor coolant swell during heatup and to accommodate water inputs from the control rod drive system.

The secondary purpose of the reactor water cleanup system is to minimize thermal stratification of the reactor vessel during periods of no recirculation flow; to provide an alternate means of vessel cooldown; and to provide continuous water quality monitoring for conductivity, pH, oxygen, and silica. The reactor water cleanup system accomplishes these purposes by forced circulation of reactor coolant through heat exchangers and filter-demineralizers.

LRA Table 2.3.3-24 identifies the components subject to an AMR for the reactor water cleanup system by component type and intended function.

2.3.3.24.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the reactor water cleanup system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.25 Remote Shutdown Panel Room HVAC System

2.3.3.25.1 Summary of Technical Information in the Application

LRA Section 2.3.3.25 describes the remote shutdown panel room HVAC system, which is a mechanical system designed to maintain air temperature, quality, and humidity and maintain the remote shutdown panel compartment at a slight positive pressure ensuring the proper operation of controls and equipment that can be used to safely shut down the plant if the main control room is unusable.

The purpose of the remote shutdown panel room HVAC system is to provide a continuous supply of filtered and conditioned air and maintain the remote shutdown panel room compartment at a slightly positive pressure to prevent infiltration of fire, smoke, fumes, and airborne radioactivity from surrounding areas into the remote shutdown panel room compartment. The system accomplishes this by providing adequate ventilation flow capacity into the remote shutdown panel room compartment to prevent infiltration when the ventilation system is manually placed in service.

LRA Table 2.3.3-25 identifies the components subject to an AMR for the remote shutdown panel room HVAC system by component type and intended function.

2.3.3.25.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the remote shutdown panel room HVAC system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.26 Service Water Intake Ventilation System

2.3.3.26.1 Summary of Technical Information in the Application

LRA Section 2.3.3.26 describes the service water intake ventilation system, which is a normally operating forced air ventilation system designed to remove waste heat produced from the components located in the service water intake structure.

The purpose of the service water intake ventilation system is to maintain the temperatures in the two service water pump areas and traveling screen motor room within design conditions. The system accomplishes this by supplying fresh air and re-circulating air throughout the service water intake structure. This ventilation system is designed as a safety-related system and will remain operational during accident conditions.

LRA Table 2.3.3-26 identifies the components subject to an AMR for the service water intake ventilation system by component type and intended function.

2.3.3.26.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the service water intake ventilation system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.27 Service Water System

2.3.3.27.1 Summary of Technical Information in the Application

LRA Section 2.3.3.27 describes the service water system, which is a normally operating open-loop cooling system designed to provide cooling water from the Delaware River (the ultimate heat sink) to perform both safety-related and nonsafety-related functions.

The purpose of the service water system is to provide river water cooling for the closed-loop cooling water systems, safety and turbine auxiliary cooling system (SACS), and the reactor auxiliary cooling system (RACS). The system accomplishes this by supplying strained river water from the ultimate heat sink to the tube side of the SACS and RACS heat exchanger and discharging the heated water to the cooling tower basin or overboard discharges.

During normal operating conditions and loss of offsite power conditions, the service water system provides river water cooling to the SACS and RACS. During a LOCA and other DBAs, the service water system provides river water only to the SACS, and the RACS is automatically isolated. The service water system operation is initiated manually or automatically. Automatic operation includes service water system pump starts and isolation of nonsafety-related components.

LRA Table 2.3.3-27 identifies the components subject to an AMR for the service water system by component type and intended function.

2.3.3.27.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the service water system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.28 Standby Diesel Generator Area Ventilation Systems

2.3.3.28.1 Summary of Technical Information in the Application

LRA Section 2.3.3.28 describes the standby diesel generator area ventilation system, which is a normally operating mechanical system designed to provide proper environmental conditions within each of the compartments contained in the auxiliary building control and diesel structure.

The purpose of the standby diesel generator area ventilation system is to maintain compartment environmental conditions using cooling, heating, and ventilation throughout the diesel portion of the auxiliary building control and diesel generator area building. The system accomplishes this by regulating temperature and ventilating air in the diesel building compartments during normal and accident conditions.

LRA Table 2.3.3-28 identifies the components subject to an AMR for the standby diesel generator area ventilation system by component type and intended function.

2.3.3.28.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the standby diesel generator area ventilation systems mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.29 Standby Diesel Generator and Auxiliary Systems

2.3.3.29.1 Summary of Technical Information in the Application

LRA Section 2.3.3.29 describes the standby diesel generator and auxiliary system, which is a standby mechanical system designed to provide power to Class 1E and selected non-Class 1E loads that are needed for safe and orderly shutdown of the reactor, maintaining the plant in a safe shutdown condition and mitigating the consequences of a DBA in the event the preferred power source is not available.

The purpose of the standby diesel generator and auxiliary system is to independently provide sufficient power to energize all equipment required for safely shutting down the reactor. The system accomplishes this by using diesel engines to rotate electric generators attached to the diesel engines.

The standby diesel generator and auxiliary system uses four diesel generator units located in separate rooms of the auxiliary building. Each diesel engine will be automatically started under LOCA conditions (reactor low-low level, a high drywell pressure signal), and/or loss of power condition (undervoltage condition in the 4,160-volt AC system), or by core spray system manual initiation.

LRA Table 2.3.3-29 identifies the components subject to an AMR for the standby diesel generator and auxiliary system by component type and intended function.

2.3.3.29.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the standby diesel generator and auxiliary systems mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.30 Standby Liquid Control System

2.3.3.30.1 Summary of Technical Information in the Application

LRA Section 2.3.3.30 describes the standby liquid control system, which is a standby and redundant sodium pentaborate injection system that is used if the normal reactivity control provisions become inoperative, and can be used at anytime in core life. This system acts independently from the control rod drive system. The most severe requirement for which the system is designed is shutdown from a full power operating condition assuming complete failure of the control rod drive system to respond to a scram signal.

The purpose of the standby liquid control system is to provide sufficient capacity for controlling the reactivity difference between the steady state rated operating condition of the reactor and the cold shutdown condition, including shutdown margin, thereby ensuring complete shutdown capability from the most reactive condition, at any time in core life. The system accomplishes this by injecting sodium pentaborate solution into the reactor vessel to absorb neutrons. The neutron absorber is dispersed within the reactor core in sufficient quantity to provide a reasonable margin for dilution leakage and imperfect mixing. The standby liquid control system is not provided as a backup for reactor trip functions, since most transient conditions that require reactor trip occur too rapidly to be controlled by the standby liquid control system. Standby liquid control operation is initiated automatically by signals from redundant reactivity control system or can be initiated manually.

The standby liquid control system consists of a storage tank, two positive displacement pumps, two explosive valves, a test tank, and associated piping and valves. The system takes suction from the storage tank and pumps borated water directly into the reactor vessel near the bottom of the core shroud. The boron acts as a neutron absorber and shuts down the reactor.

LRA Table 2.3.3-30 identifies the components subject to an AMR for the standby liquid control system by component type and intended function.

2.3.3.30.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the standby liquid control system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.31 Torus Water Cleanup System

2.3.3.31.1 Summary of Technical Information in the Application

LRA Section 2.3.3.31 describes the torus water cleanup system, which is a mechanical system designed to maintain torus water purity, clarity, and level within specified limits. The torus water cleanup system has no function related to the safe shutdown of the plant. It can be operated during startup, shutdown, and refueling modes, as well as during power operation.

The purpose of the torus water cleanup system is to maintain suppression pool water quality within its limits. The torus water cleanup system accomplishes this purpose by processing torus water through the fuel pool cooling and cleanup system's filter demineralizer.

The torus water cleanup system is manually initiated and operated intermittently, as necessary, to maintain suppression pool water quality within its limits.

LRA Table 2.3.3-31 identifies the components subject to an AMR for the torus water cleanup system by component type and intended function.

2.3.3.31.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.31, UFSAR Section 9.1.3, and the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In a letter dated April 15, 2010, the staff issued RAI 2.3.3.31-01 and noted that they could not locate anchors on license renewal drawings LR-M-53-1, sheet 2 (lines O-EC-6”-HBD-025 and EE-6”-HCD-001) and LR-M-53-1, sheet 1 (lines 8”-HBD-002 and 8”-HCD-001). The applicant was requested to provide additional information to locate the anchors for the O-EC-6”-HBD-025, EE-6”-HCD-001, 8”-HBD-002, and 8”-HCD-001 lines between the end of the (a)(2) scoping boundary and the safety-nonsafety interface. The staff needed the information to determine if the applicant appropriately extended the boundary beyond the safety-nonsafety interface.

The applicant's response, dated May 11, 2010, described the location of the anchors, which are within the existing (a)(2) scoping boundary. This conforms to the applicant's methodology and did not result in the inclusion of any additional components within the scope of license renewal. Based upon its review, the staff finds the applicant's response to RAI 2.3.3.31-01 acceptable.

2.3.3.31.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the torus water cleanup system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.32 Traversing Incore Probe System

2.3.3.32.1 Summary of Technical Information in the Application

LRA Section 2.3.3.32 describes the traversing incore probe (TIP) system, which is an electrical instrumentation system designed to provide neutron flux data to be used for calibration of the local power range monitor (LPRM) detectors and to determine axial neutron flux levels for core power distribution measurements. The TIP system includes mechanical component types that are responsible for providing primary containment integrity.

The purpose of the TIP system is to measure core neutron flux at various positions throughout the core. The system accomplishes this by using a set of fission chamber detector instruments identical to those used by the LPRM system and a positioning system capable of moving the fission chamber detectors to various locations in the core corresponding to the locations of the

LPRM detectors. The moveable TIP detectors, as with fixed LPRM detectors, generate signals that are processed to indicate neutron flux levels in the vicinity of each detector.

LRA Table 2.3.3-32 identifies the components subject to an AMR for the TIP system by component type and intended function.

2.3.3.32.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the TIP system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion Systems

LRA Section 2.3.4 identifies the steam and power conversion systems SCs subject to an AMR for license renewal. The applicant described the supporting SCs of the steam and power conversion systems in the following LRA sections:

- LRA Section 2.3.4.1, "Condensate Storage and Transfer System"
- LRA Section 2.3.4.2, "Feedwater System"
- LRA Section 2.3.4.3, "Main Condenser System"
- LRA Section 2.3.4.4, "Main Steam System"

2.3.4.1 Condensate Storage and Transfer System

2.3.4.1.1 Summary of Technical Information in the Application

LRA Section 2.3.4.1 describes the condensate storage and transfer system, which is a condensate storage, makeup, and supply system designed to distribute water to the HPCI, reactor core isolation cooling, core spray, control rod drive, RHR, reactor water cleanup, fuel pool cooling and cleanup, condensate, feedwater, and radwaste systems for normal and testing operational modes. The system is normally filled by the makeup demineralizer system and operated continuously during plant power operation.

The purpose of the condensate storage and transfer system is to provide for: (1) the bulk storage of condensate surge volume capability for the condensate system, (2) condensate supply for the condensate demineralizer resin transfer, (3) flushing, (4) seal water, (5) resin regeneration, and (6) makeup to the fuel pool cooling and cleanup system. The system supplies condensate to the suction of the HPCI, reactor core isolation cooling, core spray, and control rod drive pumps. The system also supplies condensate and makeup supply to various plant systems.

The condensate storage and transfer system accomplishes this by continuously delivering pressurized condensate from the condensate transfer, condensate transfer jockey, or the refueling water pumps to individual plant systems. It also provides a flow path between plant water supplies and various equipment when the appropriate manual or remote manual line-ups are made.

LRA Table 2.3.4-1 identifies the components subject to an AMR for the condensate storage and transfer system by component type and intended function.

2.3.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1, UFSAR Section 9.2.6, and the license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In a letter dated April 15, 2010, the staff issued RAI 2.3.4.1-01 and noted that license renewal drawing LR-M-51-1, sheet 1, location H-6, shows 10 CFR 54.4(a)(2) line AP-4"-HCD-022 connected to 10 CFR 54.(a)(1) line AP-4"GBB-030. The applicant was requested to provide additional information to locate the anchors for this line between the end of the 10 CFR 54.4 (a)(2) scoping boundary and the safety-nonsafety interface. The staff needed the information to determine if the applicant appropriately extended the boundary beyond the safety-nonsafety interface.

The applicant's response, dated May 11, 2010, described the location of the anchors, which are within the existing 10 CFR 54.4 (a)(2) scoping boundary. This conforms to the applicant's methodology and did not result in the inclusion of any additional components within the scope of license renewal. Based upon its review, the staff finds the applicant's response to RAI 2.3.4.1-01 acceptable.

2.3.4.1.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the condensate storage and transfer system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.2 Feedwater System

2.3.4.2.1 Summary of Technical Information in the Application

LRA Section 2.3.4.2 describes the feedwater system, which is a normally operating system designed to provide preheated feedwater to the RPV. It provides water to the reactor at a flow rate equivalent to what is being generated into steam by boil-off and removed by the main steam system.

The purpose of the feedwater system is to provide preheated feedwater to the RPV during normal operation. The system accomplishes this by delivering high-pressure feedwater to the reactor vessel. The feedwater system automatically maintains the desired RPV water level for all normal reactor operating conditions.

The feedwater system provides cooling water to the reactor core during a LOCA but is not credited in the accident analyses, and is not considered part of the ECCS or credited to support safe shutdown.

LRA Table 2.3.4-2 identifies the components subject to an AMR for the feedwater system by component type and intended function.

2.3.4.2.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the feedwater system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.3 Main Condenser System

2.3.4.3.1 Summary of Technical Information in the Application

LRA Section 2.3.4.3 describes the main condenser system, which is 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 system provides for post-accident containment and holdup of activity products.

The purpose of the main condenser system is to condense and deaerate low-pressure turbine exhaust from each of the low-pressure turbines, reactor feed pump turbine exhaust steam, main turbine bypass steam, and other steam influents. It also provides a retention time to allow for the decay of short-lived radionuclides. The system accomplishes this by transferring heat to the circulating water system and by ensuring sufficient retention time in the hotwell to allow for the decay of short-lived isotopes.

LRA Table 2.3.4-3 identifies the components subject to an AMR for the main condenser system by component type and intended function.

2.3.4.3.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the main condenser system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.4 Main Steam System

2.3.4.4.1 Summary of Technical Information in the Application

LRA Section 2.3.4.4 describes the main steam system, which is a normally pressurized system designed to deliver steam from the reactor to the main turbine and auxiliary system.

The purpose of the main steam system is to provide a primary containment and reactor coolant pressure boundary function, serve as a pressure relief system, and serve as a steam distribution system. The system accomplishes the primary containment and reactor coolant pressure boundary function by using piping and valves to limit reactor coolant inventory or radioactive release to within acceptable limits. The main steam system accomplishes the pressure relief function for the reactor coolant pressure boundary by way of automatic or manual actuation of safety relief valves. It also provides automatic or manual reactor depressurization to support low-pressure ECCS operation. Distribution of steam to the main turbine and auxiliary systems is accomplished by piping distribution branches in the turbine building.

LRA Table 2.3.4-4 identifies the components subject to an AMR for the main steam system by component type and intended function.

2.3.4.4.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the main steam system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4 Scoping and Screening Results: Structures

This section documents the staff's review of the applicant's scoping and screening results for structures. Specifically, this section describes the following structures:

- auxiliary boiler building
- auxiliary building control/diesel generator area
- auxiliary building service/radwaste area
- component supports commodity group
- fire water pump house
- piping and component insulation commodity group
- primary containment
- reactor building
- service water intake structures
- shoreline protection and dike
- switchyard
- turbine building
- yard structures

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant identified and listed passive, long-lived SCs that are within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff focused its review on the implementation results. This approach allowed the staff to confirm that there were no omissions of structural components that meet the scoping criteria and are subject to an AMR.

The staff's evaluation of the information provided in the LRA was performed in the same manner for all structures. The objective of the review was to determine if the structural components that appeared to meet the scoping criteria specified in the Rule, were identified by the applicant as within the scope of license renewal, in accordance with 10 CFR 54.4. Similarly, the staff evaluated the applicant's screening results to verify that all long-lived, passive SCs were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

To perform its evaluation, the staff used the guidance in SRP-LR Section 2.4, "Scoping and Screening Results: Structures," and reviewed the applicable LRA sections, focusing its review on components that had not been identified as within the scope of license renewal. The staff reviewed the UFSAR for each structure to determine if the applicant had omitted components with intended functions required by 10 CFR 54.4(a) from the scope of license renewal. The staff also reviewed the UFSAR to determine if all intended functions required by 10 CFR 54.4(a) were specified in the LRA. If omissions were identified, the staff requested additional information to resolve the discrepancies.

After completing its review of the scoping results, the staff evaluated the applicant's screening results. For those components with intended functions, the staff sought to determine: (1) if the functions are performed with moving parts or a change in configuration or properties, or (2) if they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those that did not meet either of these criteria, the staff sought to confirm that these structural components were subject to an AMR as required by

10 CFR 54.21(a)(1). If discrepancies were identified, the staff requested additional information to resolve them.

2.4.1 Auxiliary Boiler Building

2.4.1.1 Summary of Technical Information in the Application

LRA Section 2.4.1 describes the auxiliary boiler building (ABB) as a single story, structural steel and concrete masonry unit structure located north of the reactor building. It is located in the yard, physically separated from safety-related SSCs such that its failure would not impact a safety-related function. It consists of a single story structure partitioned into three areas: the auxiliary steam boiler area, water treatment room, and a unit substation room.

The purpose of the ABB is to provide physical support, shelter, and protection for the nonsafety-related auxiliary steam and fresh water supply system components and switchgear for the yard electrical substation. Additionally, it houses other components such as oil-fired boilers, a deaerator, three boiler feedwater pumps, fresh water tanks and pumps, ventilation, and electrical and supporting equipment.

LRA Table 2.4-1 identifies the components subject to an AMR for the ABB by component type and intended function.

2.4.1.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the ABB SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2 Auxiliary Building Control and Diesel Generator Area

2.4.2.1 Summary of Technical Information in the Application

LRA Section 2.4.2 describes the auxiliary building control and diesel generator area building as a multi-story structure comprised of reinforced concrete walls, slabs, foundation mat, roof, and structural steel. It is physically located adjacent to, and north of, the reactor building. The auxiliary building control and diesel generator area is classified as a seismic Category I structure and is divided into compartments designed to provide physical separation for redundant mechanical and electrical safety-related components. It also contains unoccupied space, empty rooms, or rooms with abandoned equipment from the Unit 2 plant cancelled areas.

The auxiliary building control and diesel generator area building foundation consists of a reinforced concrete mat placed on engineered structural backfill that bears on the dense Vincentown Formation. Seismic separation joints separate the foundation and building walls from the abutting buildings.

The diesel generator area is located in the western portion of the building. The purpose of the diesel generator area is to house the diesel fuel tanks, standby diesel generators, ventilation and electrical equipment, and supporting systems.

The control area is located in the eastern portion of the building. The purpose of the control area is to house the control room, cable spreading rooms, computer rooms, battery rooms, ventilation and electrical equipment, and supporting systems. The control room envelope construction joints and penetrations for cable, pipe, HVAC duct, HVAC equipment, dampers, and doors are designed specifically for leak tightness. The Unit 2 cancelled control rooms were reconfigured for office space and conference rooms and are separate from the main control room.

The purpose of the auxiliary building control and diesel generator area is to provide structural support, shelter, and protection to safety-related SSCs housed within it during normal plant operation, and during and following postulated DBAs and extreme environmental conditions. The control and diesel generator area ventilation systems are evaluated with the auxiliary building ventilation system.

LRA Table 2.4-2 identifies the components subject to an AMR for the auxiliary building control and diesel generator area by component type and intended function.

2.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

During its review of LRA Section 2.4.2, the staff identified an area in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results for the auxiliary building control and diesel generator area.

In a letter dated March 31, 2010, the staff issued RAI 2.4-2 and requested clarification regarding the reinforced concrete isolation walls since they are included in LRA Table 2.4-2 (auxiliary building control and diesel generator area) but their isolation function is not listed as an intended function in any concrete component listed in the aforementioned table.

In its response dated April 22, 2010, the applicant stated that the reinforced concrete isolation walls are described in UFSAR Section 3.8.4.1.2 and LRA Section 2.4.2. The walls perform the isolation function by fulfilling all of the following intended functions: "flood barrier, HELB and medium energy line breaks (MELB) shielding, missile barrier, shelter, protection, shielding and structural support." All of these functions are listed in LRA Table 2.4-2 for component type "concrete: interior" thus, there is no need for the additional intended function "isolation."

Based on its review, the staff finds the applicant's response to RAI 2.4-2 acceptable because the isolation function for the reinforced concrete isolation walls in the auxiliary building control and diesel generator area have not been excluded from the scope of license renewal and are subject to an AMR. Therefore, the staff's concern described in RAI 2.4-2 is resolved.

2.4.2.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the auxiliary building control and diesel generator area SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.3 Auxiliary Building Service and Radwaste Area

2.4.3.1 Summary of Technical Information in the Application

LRA Section 2.4.3 describes the auxiliary building service and radwaste area as a multi-story structure, separated into three sections and constructed of reinforced concrete and structural steel. Additionally, the structure has reinforced concrete panel walls, removable concrete and lead block shielding plugs that are restrained with metal decking, and built-up roofing over the reinforced concrete roof slab. It is located adjacent to, and east of, the reactor building.

The building is classified as a seismic Category I structure and has seismic joints that separate the foundation mats and building walls of the structure sections and the abutting turbine building.

The purpose of the auxiliary building service and radwaste area is to provide structural support, shelter, and protection to safety-related SSCs housed within it during normal plant operation, and during and following postulated DBAs and extreme environmental conditions.

The building contains the remote shutdown panel, a section of the main steam line tunnel, cable tray areas, a pipe way, radwaste treatment and storage facilities, chemical lab, heating and ventilation equipment, machine shops, decontamination equipment, and personnel support facilities. Additionally, it also supports and protects nonsafety-related SSCs whose failure could impact a safety-related function.

LRA Table 2.4-3 identifies the components subject to an AMR for the auxiliary building service and radwaste area by component type and intended function.

2.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

During its review of LRA Section 2.4.3, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant’s scoping and screening results for the auxiliary building service and radwaste area.

In a letter dated March, 31, 2010, the staff issued RAI 2.4-1 and requested that the applicant clarify which components included the main steam tunnel structural elements in LRA Table 2.4-3 (auxiliary building service and radwaste area) or justify their omission from scope.

In its response dated April 22, 2010, the applicant stated that the main steam structural components are included in LRA Table 2.4-3. They are composed of the following component types: “blowout panel, concrete embedments, concrete: interior, penetration sleeves, spray shields and steel components: all structural steel.”

Based on its review, the staff finds the response to RAI 2.4-1 acceptable because the main steam tunnel structural elements have not been excluded from the scope of license renewal and are subject to an AMR. The staff's concern described in RAI 2.4-1 is resolved.

2.4.3.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the auxiliary building service and radwaste area SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.4 Component Supports Commodity Group

2.4.4.1 Summary of Technical Information in the Application

LRA Section 2.4.4 describes the component supports commodity group as consisting of structural elements and specialty components designed to transfer the load applied from an SSC to the building structural element or directly to the building foundation. The commodity group is comprised of the following supports:

- supports for American Society of Mechanical Engineers (ASME) Class 1, 2, and 3 piping and components, including reactor vessel to biological shield wall stabilizer, reactor vessel skirt support anchorage, reactor vessel support ring girder and anchorage, control rod drive housing supports, and service water pumps
- supports for ASME Class Metal Containment (MC) components, including suppression chamber seismic restraints, suppression chamber support saddles and columns, and vent system supports
- supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, and non-ASME piping and components
- supports for racks, panels, cabinets, and enclosures for electrical equipment and instrumentation
- supports for the emergency diesel generator (EDG), HVAC system components, and other miscellaneous mechanical equipment
- supports for platforms, pipe whip restraints, jet impingement shields, and other miscellaneous structures

The purpose of a support is to transfer gravity, thermal, seismic, and other lateral loads imposed on or by the SSC to the supporting building structural element or foundation. This includes support for mechanical, electrical, and instrumentation SSCs that are within the scope of license renewal.

LRA Table 2.4-4 identifies the components subject to an AMR for the component supports commodity group by component type and intended function.

2.4.4.2 Conclusion

Based on the results of the staff evaluation of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the component supports commodity group SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.5 Fire Water Pump House

2.4.5.1 Summary of Technical Information in the Application

LRA Section 2.4.5 describes the fire water pump house as a single story, above-grade concrete structure. It is physically located in the yard north of the reactor building. The structure is composed of concrete masonry block with reinforcement steel for the exterior walls and concrete masonry block walls for the interior.

The purpose of the fire water pump house is to provide structural support, shelter, and protection for components required for fire protection, such as the diesel driven fire pump, motor driven fire pump and jockey pump, associated piping and piping components, controls and instrumentation, and electrical panels and enclosures.

LRA Table 2.4-5 identifies the components subject to an AMR for the fire water pump house by component type and intended function.

2.4.5.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the fire water pump house SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.6 Piping and Component Insulation Commodity Group

2.4.6.1 Summary of Technical Information in the Application

LRA Section 2.4.6 describes the piping and component insulation commodity group as comprised of prefabricated blankets, modules, or panels made from metallic and nonmetallic materials, and engineered as integrated assemblies that fit the surface to be insulated. Metallic insulation or reflective mirror insulation is fabricated from stainless steel material and nonmetallic insulation and consists of materials such as calcium silicate, fiberglass and fiberglass molded insulation, cellular glass, and ceramic fiber.

Anti-sweat insulation used on chilled water systems consists of fiberglass insulation material jacketed with stainless steel or aluminum jacketing. The piping and component insulation commodity group is not classified as a safety-related commodity.

The purpose of piping and component insulation is to improve thermal efficiency, minimize heat loads on the HVAC systems, provide for personnel protection, prevent freezing of heat traced piping, and protect against sweating of cold piping and components. Insulation located in areas with safety-related equipment is designed to protect nearby safety-related SSC equipment from overheating and maintain its structural integrity during postulated design-basis seismic events. Insulation within the primary containment has been evaluated to ensure that it will not affect the ECCS suction strainers.

LRA Table 2.4-6 identifies the components subject to an AMR for the piping and component insulation commodity group by component type and intended function.

2.4.6.2 Conclusion

Based on the results of the staff evaluation of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the piping and component insulation commodity group SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.7 Primary Containment

2.4.7.1 Summary of Technical Information in the Application

LRA Section 2.4.7 describes the primary containment as a General Electric Mark I design and consists of a drywell, a pressure suppression chamber, and a vent system connecting the drywell and the pressure suppression chamber. It is designed, fabricated, inspected, and tested in accordance with the requirements of Subsection NE, “Requirements for MC Components,” of the ASME Boiler and Pressure Vessel (B&PV) Code, Section III. The primary containment is safety-related and classified as a seismic Category I structure.

The primary containment structure is completely enclosed by the reactor building and is composed of the primary containment structure, primary containment penetrations, and internal structures of the primary containment structure.

The purpose of the primary containment structure is to accommodate, with a minimum of leakage, the pressures and temperatures resulting from the break of any enclosed process pipe, and thereby, to limit the release of radioactive fission products to values which will ensure offsite dose rates well below 10 CFR 50.67 guideline limits. Additionally, it provides a source of water for ECCS and for pressure suppression in a LOCA event. The primary containment and internal structures also provide structural support to the RPV, the reactor coolant systems, and other safety and nonsafety-related SSCs housed within the primary containment.

The drywell is a steel pressure vessel, with a spherical lower section, a cylindrical upper section, and a removable, flanged, hemi-ellipsoidal top head. Inner and outer steel cylindrical skirts, that are encased in concrete and anchored to a concrete pedestal, support the drywell. The concrete pedestal that supports the drywell is founded on the foundation slab of the reactor building. The outer skirt is designed to transfer the drywell loads at the bottom of the drywell into the foundation. The inner skirt extends into the drywell and transfers RPV pedestal loads into the foundation. The drywell head is bolted to the drywell flange and is sealed with a double seal arrangement. Access into the drywell is through a personnel airlock/equipment hatch, with two mechanically interlocked doors, and the other is through an equipment access hatch.

The purpose of the drywell is to house the RPV, the reactor coolant recirculation system, safety relief valves, the branch connections of the reactor primary system, the drywell spray header, and internal structures. The internal structures consist of a fill slab, reactor pedestal, biological shield wall and its lateral support structural steel, and miscellaneous steel.

The pressure suppression chamber is a toroidal shaped, steel pressure vessel encircling the base of the drywell. The pressure suppression chamber, commonly called the torus, is partially filled with demineralized water and includes internal steel framing and access hatches.

The vent system consists of eight circular vent lines, which form a connection between the drywell and the pressure suppression chamber. The lines enter the pressure suppression chamber through penetrations provided with expansion bellows (inboard and outboard) and join into a common header contained within the air space of the pressure suppression chamber.

LRA Table 2.4-7 identifies the components subject to an AMR for the primary containment by component type and intended function.

2.4.7.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. During its review of LRA Section 2.4.7, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results for the primary containment.

In a letter dated March, 31, 2010, the staff issued RAI 2.4-3 and requested that the applicant clarify if the horizontal seismic restraints shown in UFSAR Figures 3.8-1 and 3.8-13 are included within the scope of license renewal per LRA Table 2.4-7 or else justify the exclusion.

In its response dated April 22, 2010, the applicant stated that the horizontal seismic restraints shown in UFSAR Figures 3.8-1 and 3.8-13 are components of the torus (suppression chamber) supports and have not been excluded from the scope.

The applicant also stated that the horizontal seismic restraints are included in the commodity group identified as ASME Class MC components which is included in LRA Table 2.4-4.

Based on its review, the staff finds the response to RAI 2.4-3 acceptable because the horizontal seismic restraints have been included within the scope of license renewal and are subject to an AMR. The staff's concern described in RAI 2.4-3 is resolved.

In a letter dated March, 31, 2010, the staff issued RAI 2.4-4 and requested that the applicant clarify where the structural elements that transfer the RPV loads to the RPV ring girder and subsequently to the RPV pedestal (shown in UFSAR Figure 3.8-1) are evaluated in the LRA.

In its response dated April 22, 2010, the applicant stated that the RPV skirt bolting, ring girder, and support anchorage are the structural elements designed to transfer the RPV loads and are included in LRA Tables 2.4-4 and 2.4-7.

The applicant also stated that the RPV skirt bolting, ring girder, and support anchorage are included in LRA Table 2.4-4 under the component type “Supports for ASME Class 1 Piping Components (support members; welds; bolted connections; support anchorage to building structure).” Additionally, the response stated that the RPV pedestal is listed in LRA Table 2.4-7 under the component type “concrete: interior (RPV pedestal).”

Based on its review, the staff finds the response to RAI 2.4-4 acceptable because the structural elements that transfer the RPV loads to the RPV ring girder and subsequently to the RPV pedestal have been included within the scope of license renewal and are, therefore, subject to an AMR. The staff’s concern described in RAI 2.4-4 is resolved.

In a letter dated March, 31, 2010, the staff issued RAI 2.4-5 and requested that the applicant clarify the inclusion of the RPV and torus ring girder (shown in UFSAR Figure 3.8-1) as components subject to an AMR per LRA Table 2.4-7, “primary containment,” since LRA Table 2.4-7 does not include these components.

In its response dated April 22, 2010, the applicant stated that the torus ring girder is included in LRA Table 2.4-7 and is within the scope of license renewal and is, therefore, subject to an AMR. Furthermore, the response stated that the RPV ring girder is included in LRA Table 2.4-4 as component type “Supports for ASME Class 1 Piping and Components (support members; welds; bolted connections; support anchorage to building structure).”

Based on its review, the staff finds the response to RAI 2.4-5 acceptable because the torus and RPV ring girders have been included within the scope of license renewal and are subject to an AMR. The staff’s concern described in RAI 2.4-5 is resolved.

In a letter dated March, 31, 2010, the staff issued RAI 2.4-6 and requested that the applicant clarify LRA Sections 2.4.7 (primary containment) and 2.4.8 (reactor building) and Tables 2.4-7 and 2.4.8 which did not clearly indicate if the following components have been included within the scope of license renewal and are subject to an AMR:

- refueling seal assembly
- weld pads on the drywell shell for attachment of pipe supports
- water seal plates at the base of the drywell head as shown in UFSAR Figure 3.8-1
- spent fuel pool liner plate leak chase system

In its response dated April 22, 2010, the applicant stated that all the aforementioned components, except the spent fuel pool liner plate leak chase system, have been included within the scope of license renewal and are subject to an AMR.

The response stated that the refueling seal assembly and water seal plates provide a seal from the reactor to the primary containment drywell shell and from the exterior of the drywell shell to the liner of the reactor refuel well to permit flooding of the reactor refuel well or cavity.

The applicant also stated that LRA Table 2.4-8 (reactor building) includes the component type “steel components: refueling bellows (RPV to drywell and drywell to reactor well),” however, the applicant determined that this component type should have also included the carbon steel seal plates, which were inadvertently omitted from the table. Therefore, LRA Table 2.4-8 (reactor building), on page 2.4-40, was revised to add the carbon steel seal plates identified as the component type "steel components: refueling bellows seal plates (RPV to drywell and drywell to reactor well)." LRA Table 3.5.2-8 (reactor building), on page 3.5-197, was also revised to add the carbon steel seal plates.

Additionally, the response stated that the weld pads on the drywell shell for attachment of pipe supports are included within LRA Table 2.4-4 (component supports commodity group) as component types "Supports for ASME Class 1 Piping and Components (support members; welds; bolted connections; support anchorage to building structure)" and "Supports for ASME Class 2 and 3 Piping and Components (support members; welds; bolted connections; support anchorage to building structure)," as shown on page 2.4-18.

Finally, the response stated that the spent fuel pool liner plate leak chase system has not been included within the scope of license renewal since leak collection channels are not safety-related and are not part of the water retaining boundary, nor are they required to maintain the structural integrity of the spent fuel pool walls. The applicant further stated that the leak chase system is not relied upon in safety analyses or plant evaluations to perform a safety function. Therefore, the spent fuel pool liner plate leak chase system and its components do not have a license renewal intended function.

Based on its review, the staff finds the response to RAI 2.4-6 acceptable because the following components:

- refueling seal assembly
- weld pads on the drywell shell for attachment of pipe supports
- water seal plates at the base of the drywell head as shown in UFSAR Figure 3.8-1
- spent fuel pool liner plate leak chase system

have all been clarified regarding their inclusion or exclusion within the scope of license renewal and those components which have not been included have been justified. The staff's concern described in RAI 2.4-6 is resolved.

In RAI 2.4-7 dated March 31, 2010, the staff requested that the applicant clarify the inclusion of the shear ties shown in UFSAR Figure 3.8-29 (biological shield plan and elevation) in LRA Table 2.4-7, since it was not clear where they had been included.

In its response dated April 22, 2010, the applicant stated that the shear ties are included within the scope of license renewal and are subject to an AMR. Furthermore, the response stated that the structural elements that comprise the biological shield wall are the shear ties, liner plates, and associated bolting and concrete. Finally, the response stated that the biological shield wall shear ties, as well as the liner plates are included as the component type "steel components: biological shield liner plates," as shown in LRA Table 2.4-7 (primary containment), and the associated bolting is included in the component type "bolting (structural)," also in LRA Table 2.4-7 (primary containment). The biological shield wall concrete is included as the component type "concrete: interior (biological shield)," as shown in LRA Table 2.4-7 (primary containment) on page 2.4-31.

Based on its review, the staff finds the response to RAI 2.4-7 acceptable because the shear ties have been included within the scope of license renewal and are subject to an AMR. The staff's concern described in RAI 2.4-7 is resolved.

2.4.7.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, the applicant's RAI response, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the primary containment SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.8 Reactor Building

2.4.8.1 Summary of Technical Information in the Application

LRA Section 2.4.8 describes the reactor building as a reinforced concrete enclosure that consists of a cylindrical containment structure topped by a toroid spherical dome, with a rectangular lower section enclosing the base of the cylinder. The reactor building is a seismic Category I reinforced concrete structure designed to maintain its structural integrity during and following postulated DBAs and extreme environmental conditions. The reactor building is comprised of 7 floor levels in the Unit 1 reactor building and the three-story, reinforced concrete and structural steel enclosure plant cancelled area, formerly the Unit 2 reactor building.

The rectangular reinforced concrete foundation mat is 14 feet thick with the bottom of the mat approximately 61 feet below plant grade and founded on engineered structural backfill that bears on the dense Vincentown Formation. The mat also supports the southern portion of the auxiliary building service and radwaste area.

The purpose of the reactor building is to minimize ground level release of airborne, radioactive fission products and to provide for controlled, elevated release through the ventilation stack of the building's atmosphere under accident conditions. Additionally, it houses the spent fuel storage pool, the steam dryer and moisture separator storage pool, the new fuel storage vault, reactor cavity, spent fuel storage pool skimmer surge tanks, reactor auxiliary equipment, refueling equipment, reactor vessel servicing equipment, and engineered safety features. It also provides a secondary containment pressure boundary, structural support, shielding, shelter, and protection for primary containment and the components housed within, against external DBEs. Finally, it serves as primary containment during reactor refueling and maintenance operations when the primary containment system is open.

The cylindrical wall above the refuel floor supports a 150-ton capacity, polar crane. Personnel access openings to the building are provided with interlocked double door air lock systems to minimize reactor building leakage.

The plant cancelled area structure is founded on a reinforced concrete foundation mat that is 14 feet thick with the bottom of the mat approximately 61 feet below plant grade and founded on engineered structural backfill that bears on the dense Vincentown Formation. The foundation is structurally independent of the other foundations, separated by a seismic joint. The building does not house any safety-related equipment and is classified as a seismic Category I structure.

LRA Table 2.4-8 identifies the components subject to an AMR for the reactor building by component type and intended function.

2.4.8.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the reactor building SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.9 Service Water Intake Structures

2.4.9.1 Summary of Technical Information in the Application

LRA Section 2.4.9 describes the service water intake structures as composed of the service water intake structure, service water chemical control building, hypochlorite storage tank dike and foundation, and service water sampling shed.

Service Water Intake Structure. The service water intake structure is a multi-story, reinforced concrete and steel structure located west of the reactor building. It is comprised of a reinforced concrete foundation mat, slabs, walls, and structural steel. The roof for the structure is reinforced concrete. The reinforced concrete foundation mat of the structure is founded on lean concrete bearing on the dense Vincentown Formation. It is classified as a seismic Category I structure.

The service water intake structure has trash racks and traveling water screens located on the western side of the structure that filter debris from the incoming flow. An outdoor gantry crane services the service water intake structure. The crane is supported from the building reinforced concrete within the building envelope and from structural steel frames outside the building boundary. The foundation for the frames consists of a reinforced concrete slab on piles.

The service water intake structure and the service water system supply cooling water drawn from the Delaware River for reactor safeguard and auxiliary equipment under all credible DBEs and DBAs. The Delaware River is the ultimate heat sink, required to provide cooling water for emergency shutdown, as well as during normal plant operation.

The purpose of the service water intake structure is to provide river water to dissipate waste heat from the plant during normal, shutdown, and accident conditions. The intake structure also provides structural support for pumps and components, which convey the river water to the plant. In addition, it provides structural support and access to electrical, mechanical, and structural components required to support the function and operation of the service water system, service water intake ventilation system (including the deicing system), steel bulkheads, trash racks, traveling water screens, access platforms, ladders, and stairs. Components that make up the service water intake structure are within the scope of license renewal except for miscellaneous steel (ladders, stairs) on the outside of the structure and the pump bay steel bulkheads. The miscellaneous steel and the bulkheads are provided for personnel access and to facilitate maintenance of the pumps. The components are nonsafety-related and their failure would not impact a safety-related function. Thus, the components do not perform an intended function and are not within the scope of license renewal.

Service Water Chemical Control Building and Hypochlorite Storage Tank Dike and Foundation. The service water chemical control building and hypochlorite storage tank dike and foundation are structures located east of the service water intake structure, and are founded on a common reinforced concrete slab on grade. The service water chemical control building is a metal prefabricated commercial grade building. The purpose of the service water chemical control building and hypochlorite storage tank dike and foundation is to house the equipment used to inject hypochlorite into the service water system. The hypochlorite storage tank dike and foundation is a combination of reinforced concrete slab and short perimeter walls that provide structural support for the storage tanks that contain the hypochlorite chemical, and functions as a fluid retaining basin in case of storage tank leakage or failure. These structures are classified as nonsafety-related and do not perform an intended function for license renewal.

Service Water Sampling Shed. The service water sampling shed is located in the yard northwest of the reactor building. The shed is a metal prefabricated commercial grade building founded on a reinforced concrete slab on grade. The purpose of the structure is to house the equipment used to sample chemicals in the service water system. The structure is classified as nonsafety-related and does not perform an intended function for license renewal.

LRA Table 2.4-9 identifies the components subject to an AMR for the service water intake structures by component type and intended function.

2.4.9.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the service water intake structures SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.10 Shoreline Protection and Dike

2.4.10.1 Summary of Technical Information in the Application

LRA Section 2.4.10 describes the shoreline protection and dike, also known as the “shoreline protective dike” as comprised of cofferdams, steel sheet piles, and rock located at the service water intake structure along the Delaware River shoreline. The original earthen shoreline dike west of the reactor building was replaced with sheet pile retaining walls and rock fill construction, extending 100 feet on both sides of the service water intake structure. This section of the shoreline protection and dike is classified as nonsafety-related and seismic Category II/I, to provide protection against shoreline recession during probable maximum hurricane (PMH) surge. An earthen dike continues north of the intake structure sheet pile retaining walls to the barge slip and south to the Salem Generating Station Units 1 and 2 structures.

The shoreline protection dike includes four 44-foot diameter sheet pile cellular cofferdams, two on each side of the service water intake structure. The cofferdams are filled with coarse aggregate with the lower part of the backfill pressure grouted.

The purpose of the shoreline protection and dike is to provide protection against shoreline recession for the service water system SCs during and following design seismic and flood events.

LRA Table 2.4-10 identifies the components subject to an AMR for the shoreline protection and dike by component type and intended function.

2.4.10.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the shoreline protection and dike SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.11 Switchyard

2.4.11.1 Summary of Technical Information in the Application

LRA Section 2.4.11 describes the switchyard as physically located in a fenced area east of the reactor building and comprised of the 500-kilovolt (kV) switchyard and a control house.

The switchyard foundation consists of reinforced concrete walls, grade beams, and isolated footings bearing on steel piles. The control house is a single story masonry wall structure, with its foundation composed of a reinforced concrete slab on steel piles. Its roof is comprised of a precast, prestressed, concrete hollow slab covered with insulation and built-up roofing. A reinforced concrete cable underground vault runs under the northern and the eastern sides of the control house. The piles for the switchyard are composed of steel pipe filled with concrete and protected with a cathodic protection system. The switchyard is classified as a nonsafety-related structure and its failure would not impact a safety-related function but meets 10 CFR 54.4(a)(3) because it is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for SBO (10 CFR 50.63).

The purpose of the switchyard is to provide structural support, shelter, and protection for the 13.8-kV station power system, and the offsite 500-kV AC system components and commodities.

LRA Table 2.4-11 identifies the components subject to an AMR for the switchyard by component type and intended function.

2.4.11.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the switchyard SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.12 Turbine Building

2.4.12.1 Summary of Technical Information in the Application

LRA Section 2.4.12 states that the structures included in the boundary of the turbine building are the turbine building and the administration facility. The section describes the turbine building as a multi-story, reinforced concrete and steel structure located adjacent to the auxiliary building service and radwaste area, and east of the reactor building. The structures included in the boundary of the turbine building are the turbine building and the administration facility. The above ground exterior walls are precast concrete panels and insulated metal siding. The roof is cellular metal deck, insulation board, and built-up roofing material supported by structural steel.

The building foundation consists of reinforced concrete mats placed on engineered structural backfill that bears on the dense Vincentown Formation. Seismic joints separate the foundation mats and building walls of the turbine building, the administration facility, and the abutting auxiliary building service and radwaste area. The turbine building is classified as a nonsafety-related, nonseismic Category I structure.

<u>The Turbine Building</u>. The turbine building encloses the steam and power conversion system and turbine auxiliary systems, reactor protection system components, and supporting systems. Major components within the building include the main turbine generator, main condensers, air ejectors, moisture separators, feedwater heaters, feed and condensate pumps, condensate demineralizers, main steam control and stop valves, and their associated piping. Radioactive components are enclosed within heavy concrete walls with labyrinth entrances for shielding purposes. Some interior walls, required for separation, radiation shielding, or fire protection, are constructed of fully grouted reinforced concrete masonry units. The building also houses other nonsafety-related electrical and mechanical equipment and components, such as the motor generator sets for reactor recirculation pumps, condensate storage and transfer pumps, the demineralizer system, HVAC equipment, electrical equipment and components, and instrumentation and their enclosures, as applicable. Two 220-ton overhead cranes are provided above the turbine generator operating floor to service the turbine generator unit. The turbine generator is supported by a free standing, reinforced concrete pedestal founded on a reinforced concrete mat foundation, and the pedestal extends to the operating floor. The operating floor framing is supported on slide bearings that are in turn, supported by the pedestal. Separation joints are provided between the pedestal and walls and other turbine building floors to prevent the transfer of turbine vibration to the building.

The turbine building houses the main condenser system to provide shielding for post-accident containment and holdup. The turbine building also provides shielding from radiation exposure to allow personnel access to operate and maintain equipment.

The purpose of the turbine building is to provide structural support, shelter, and protection for SSCs classified as safety and nonsafety-related. The safety-related components housed within the turbine building are fail-safe by design, and the failure of nonsafety-related SSCs cannot prevent the accomplishment of the safety-related intended function.

<u>The Administration Facility</u>. The administration facility contains office, warehouse, and unoccupied space, or empty rooms from the Unit 2 plant cancelled areas. The old Unit 2 turbine generator-operating floor and lay down area is a common storage area with the turbine building generator-operating floor. The administration facility first (grade level) and second floors were

reconfigured for office space, conference rooms, a cafeteria, and supporting facilities that have no safety-related function.

Reactor protection system sensors are mounted on the turbine to monitor first stage pressure, main control valve fast closure, and stop valve closure and on the main condenser to measure condenser vacuum. This safety-related equipment is located in the turbine building. The sensors are safety-related, however, they are physically mounted on equipment that is not seismic Category I, and are located in the turbine building, which is not a seismic Category I structure. The reactor protection system is a fail-safe design, with other diverse safety-related reactor scram signals such that no single failure or credible natural disaster can prevent a reactor scram. Therefore, failure of the turbine components or structure will not result in a failure of the reactor protection system to attain its fail-safe state and scram the reactor. This system is evaluated with the reactor protection system.

LRA Table 2.4-12 identifies the components subject to an AMR for the turbine building by component type and intended function.

2.4.12.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the turbine building SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.13 Yard Structures

2.4.13.1 Summary of Technical Information in the Application

LRA Section 2.4.13 describes the yard structures as comprised of the compressed gas storage areas, concrete box valve pits, condensate storage tank dike and foundation, fire water tank foundations, light poles, manholes, handholes and duct banks, miscellaneous yard structures, transformer foundations, transmission towers and foundations, trenches, and yard drainage catch basins and ditch.

The purpose of the yard structures is to provide structural support, shelter, and protection for safety-related and nonsafety-related components and commodities, including components credited for SBO and fire protection. In addition, the condensate storage tank dike and foundation protects against the uncontrolled release of condensate water to the environment. Other functions of the yard structures include drainage of the yard area, lighting, and personnel and vehicular access throughout the yard area.

<u>Compressed Gas Storage Areas</u>. Compressed gas storage areas are comprised of the carbon dioxide storage facility, hydrogen storage facility, liquid oxygen storage facility, and nitrogen storage facility. The compressed gas storage areas are reinforced concrete slab foundations on grade facilities that are located in the yard area. The compressed gas storage areas are nonsafety-related and separated from safety-related SSCs such that their failure would not impact a safety-related function. The compressed gas storage areas do not perform an intended function and are not within the scope of license renewal.

<u>Concrete Box Valve Pits</u>. The concrete box valve pits are located in the yard area and are buried below plant grade with a removable concrete panel on top. There are access openings in the concrete panels with covers to allow personnel access into the valve pits. The valve pits contain nonsafety-related piping and valves for not in-scope plant water systems, including the circulating water system and the not in-scope portion of the service water system. The concrete valve pits are located at grade level and below. They are separated from safety-related SSCs, except for valve pits 4 and 5, such that their failure would not impact a safety-related function. Valve pits 4 and 5 are located adjacent to the west wall of the Unit 1 reactor building, and failure of these valve pits and enclosed components would not affect the license renewal intended functions of the reactor building or enclosed mechanical piping system. The reinforced concrete box valve pits do not perform an intended function and are not within the scope of license renewal.

<u>Condensate Storage Tank Dike and Foundation</u>. The condensate storage tank dike and foundation is a reinforced concrete structure located south of the reactor building. The structure has a 2 feet thick rectangular reinforced concrete foundation slab with the top of the slab approximately 9 feet below plant grade. The reinforced concrete foundation slab of the structure is founded on lean concrete bearing on the dense Vincentown Formation. An octagonal reinforced concrete slab, approximately 2 feet thick, is cast on the foundation slab and functions as the foundation pedestal for the condensate storage tank. There are 2 feet thick reinforced concrete walls, approximately 20 feet in height, along the edge of the foundation slab that form an open top box structure. The structure has been sized to contain any spillage due to the failure of the condensate storage tank. A reinforced concrete valve pit is located on the east side of the condensate storage tank dike. This valve pit is a rectangular open top box structure similar to the condensate storage tank dike, with the perimeter walls extending approximately 1 foot above plant grade and with grating over the open top. The condensate storage tank dike and foundation is classified as a seismic Category I structure. The condensate storage tank dike and foundation perform license renewal intended functions and are within the scope of license renewal.

<u>Fire Water Tank Foundations</u>. The fire water tank foundations are two octagonal reinforced concrete slabs on grade and are approximately 3 feet thick. The tank foundations are located north of the reactor building in the yard, separated from safety-related SSCs such that their failure would not impact a safety-related function. There is a reinforced concrete valve pit located on the south end of each tank foundation and they extend approximately 6 feet under the tank foundation. The valve pit is a rectangular box structure with perimeter walls extending approximately 1 foot above plant grade and a foundation slab approximately 10 feet below plant grade. There is a reinforced concrete slab that serves as a roof over the valve pit, with an opening that has a manhole cover for personnel access. The valve pit foundation consists of a reinforced concrete slab with piles under the perimeter walls. The fire water tank foundations perform an intended function and are within the scope of license renewal.

<u>Light Poles</u>. Light poles are metal poles that are mounted on concrete pier foundations located in the yard area. The light poles provide area lighting for the safe movement of personnel and for security surveillance, and are classified as nonsafety-related. Light poles do not perform an intended function and are not within the scope of license renewal.

<u>Manholes, Handholes, and Duct Banks</u>. Manholes and handholes consist of reinforced concrete rectangular box structures buried underground with a reinforced concrete panel on top. The manholes have an opening and cover to allow plant personnel access to electrical cables routed in duct banks. Manholes and handholes serve as intermediate connection points of duct

banks routed in the yard area. There are safety-related and nonsafety-related manholes located in the yard area. Manhole covers are provided at the openings for shelter and protection.

Duct banks are comprised of the placement of multiple raceways in an excavated trench in the yard that are encased in concrete and then backfilled with soil or engineered compacted backfill. The duct banks are used to route nonsafety-related and safety-related cables between structures and in the switchyard area. Safety-related duct banks that are buried in the yard are provided with a reinforced concrete protection slab that is cast over the duct bank for missile protection.

Manholes, handholes, and duct banks perform an intended function and are within the scope of license renewal.

Miscellaneous Yard Structures. Miscellaneous yard structures, located in the yard area, are not uniquely tied to a group of common structures in the yard. These miscellaneous yard structures include roadways, sidewalks, fences, bollards, lift stations, reinforced concrete foundation slabs for buildings that have been removed from the site, concrete pads for commercial grade HVAC units for office buildings, abandoned concrete equipment foundations, plant security shooting range and facility complex, and miscellaneous yard sheds and foundations. The miscellaneous yard structures are nonsafety-related and separated from safety-related SSCs. The miscellaneous yard structures do not perform an intended function and are not within the scope of license renewal.

Transformer Foundations. Transformer foundations are reinforced concrete slabs that provide structural support for station transformers located in the yard area. The foundations can be concrete slabs on grade, concrete slabs that are cast on a subgrade foundation several feet below grade, or on piles with perimeter walls with a pedestal type concrete equipment pad on the foundation slab that provides the structural support for the transformer. Transformer foundations are classified as nonsafety-related and do not perform a safety-related function. There are transformers that are required to support SBO restoration and, therefore, those foundations are within the scope of license renewal.

Transmission Towers and Foundations. Transmission towers and foundations are tall steel tower structures that are supported on reinforced concrete pier foundations located in the yard area. The transmission towers are located between the HCGS switchyard and the Salem Generating Station (Salem) switchyard. These transmission towers support the 500-kV power lines that are routed between the HCGS and Salem switchyards. Transmission towers and foundations are classified as nonsafety-related and do not perform a safety-related function. These transmission towers are required to support the SBO restoration function and, therefore, are within the scope of license renewal.

Trenches. Trenches are reinforced concrete rectangular box structures with open tops that are buried in excavated trenches in the yard area, with either a metal grating or metal plate covering the open tops. The trenches are used to route piping and components for not in-scope plant systems. The top of the trenches are located at approximately 6 inches above plant grade with the remaining portion of the trenches below grade such that their failure would not impact a safety-related function. The trenches do not perform an intended function and are not within the scope of license renewal.

Yard Drainage Catch Basins and Ditch. Yard drainage catch basins are reinforced concrete box structures that are buried in the yard, with an open top that has slotted grating. The yard ditch is an open channel earthen feature located along the northern boundary of the station's property. These features are provided to drain the station's yard area during normal and severe rainstorms. The yard drainage catch basins and ditch do not perform an intended function and are not within the scope of license renewal.

LRA Table 2.4-13 identifies the components subject to an AMR for the yard structures by component type and intended function.

2.4.13.2 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the yard structures SSCs within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.5 Scoping and Screening Results: Electrical and Instrumentation and Controls Systems

This section documents the staff's review of the applicant's scoping and screening results for the electrical and I&C systems. Specifically, this section discusses:

- Electrical and I&C Component Commodity Groups

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant identified and listed passive, long-lived SSCs that are within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff focused its review on the implementation results. This approach allowed the staff to confirm that there were no omissions of electrical and I&C system components that meet the scoping criteria and are subject to an AMR.

The staff's evaluation of the information provided in the LRA was performed in the same manner for all electrical and I&C systems. The objective of the review was to determine if the components and supporting structures for electrical and I&C systems that appear to meet the scoping criteria specified in the Rule, were identified by the applicant as within the scope of license renewal, in accordance with 10 CFR 54.4. Similarly, the staff evaluated the applicant's screening results to verify that all long-lived, passive SSCs were subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

To perform its evaluation, the staff used the guidance in SRP-LR Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Controls Systems," and reviewed the applicable LRA sections, focusing its review on components that had not been identified as within the scope of license renewal. The staff reviewed the UFSAR for each electrical and I&C system to determine if the applicant had omitted components with intended functions required by 10 CFR 54.4(a) from the scope of license renewal. The staff also reviewed the UFSAR to determine if all intended functions required by 10 CFR 54.4(a) were specified in the LRA. If omissions were identified, the staff requested additional information to resolve the discrepancies.

After completing its review of the scoping results, the staff evaluated the applicant's screening results. For those SSCs with intended functions, the staff sought to determine: (1) if the functions are performed with moving parts or a change in configuration or properties, or (2) if the SSCs are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those that did not meet either of these criteria, the staff sought to confirm that these SSCs were subject to an AMR, as required by 10 CFR 54.21(a)(1). If discrepancies were identified, the staff requested additional information to resolve them.

2.5.1 Electrical and Instrumentation and Controls Component Commodity Groups

2.5.1.1 Summary of Technical Information in the Application

LRA Section 2.5 describes the electrical and I&C systems. The scoping method includes all plant electrical and I&C components. Evaluation of electrical systems includes electrical and I&C components in mechanical systems. The plant-wide basis approach for the review of plant equipment eliminates the need to indicate each unique component and its specific location and precludes improper exclusion of components from an AMR.

The electrical and I&C components that were identified to be within the scope of license renewal have been grouped by the applicant into component commodity groups. The applicant has applied the screening criteria in 10 CFR 54.21(a)(1)(i) and 10 CFR 54.21(a)(1)(ii) to this list of component commodity groups to identify those that perform their intended functions without moving parts or without a change in configuration or properties, and to remove the component commodity groups that are subject to replacement based on a qualified life or specified time period.

LRA Table 2.5.2-1 identifies the components subject to an AMR for the electrical commodity groups by component type and intended function.

2.5.1.2 Staff Evaluation

The staff reviewed LRA Section 2.5 and UFSAR Sections 7 and 8 using the evaluation methodology described in SER Section 2.5 and the guidance in SRP-LR Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Controls Systems."

During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant has not omitted from the scope of license renewal any components with intended functions required by 10 CFR 54.4(a). The staff then reviewed those components that the applicant has identified as within the scope of license renewal to verify that the applicant has not omitted any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

General Design Criteria 17 of 10 CFR Part 50, Appendix A, requires that electric power from the transmission network to the onsite electric distribution system be supplied by two physically independent circuits to minimize the likelihood of their simultaneous failure. In addition, the staff noted that the guidance provided by letter dated April 1, 2002, "Staff Guidance on Scoping of Equipment Relied on to Meet the Requirements of the Station Blackout Rule (10 CFR 50.63) for License Renewal (10 CFR 54.4(a)(3))," states:

> For purposes of the license renewal rule, the staff has determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of the rule. This path typically includes switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and onsite electrical system, and the associated control circuits and structures. Ensuring that the appropriate offsite power system long-lived passive SSCs that are part of this circuit path are subject to an AMR will assure that the bases underlying the SBO requirements are maintained over the period of extended license.

The applicant included the complete circuits between the onsite circuits and up to, and including, switchyard breakers (including the associated controls and structures) within the scope of license renewal. Figure 2.1-2, "Hope Creek Offsite Power for SBO," indicates the SBO recovery path and electrical distribution systems. LRA Section 2.5.1 states that the scoping boundary consists of six 500-kV switchyard circuit breakers (30X, 31X, 50X, 51X, 60X, and

61X). Consequently, the staff concludes that the scoping is consistent with the guidance issued April 1, 2002, and later incorporated in SRP-LR Section 2.5.2.1.1.

In the LRA, the applicant stated that cable tie-wraps are used to bundle wires and cables together to maintain the cable runs neat and orderly. The cable tie-wraps are not credited for maintaining cable ampacity, ensuring maintenance of cable minimum bending radius, or maintaining cables within vertical raceways. Furthermore, the applicant is not crediting the use of cable tie-wraps in the seismic qualification of cable trays. Based on the review of this information and the UFSAR, the staff finds the applicant's exclusion of cable tie-wraps from the SSCs subject to an AMR, acceptable.

2.5.1.3 Conclusion

Based on the results of the staff evaluation of the LRA, UFSAR, and applicable boundary drawings, the staff concludes that the applicant has appropriately identified the electrical and I&C systems components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.6 Conclusion for Scoping and Screening

The staff reviewed the information in LRA Section 2, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results." The staff finds that the applicant's scoping and screening methodology is consistent with the requirements of 10 CFR 54.21(a)(1) and the staff's position on the treatment of safety-related and nonsafety-related SSCs within the scope of license renewal, and the SCs requiring an AMR are consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

On the basis of its review, the staff concludes that the applicant has adequately identified those SSCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and those SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

With regard to these matters, the staff concludes that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and any changes made to the CLB, to comply with 10 CFR 54.21(a)(1), are in accordance with NRC regulations.

SECTION 3

AGING MANAGEMENT REVIEW RESULTS

This section of the safety evaluation report (SER) evaluates aging management programs (AMPs) and aging management reviews (AMRs) for Hope Creek Generating Station (HCGS), by the staff of the United States Nuclear Regulatory Commission (NRC or the staff).

In Appendix B of its license renewal application (LRA), PSEG Nuclear, LLC (PSEG or the applicant) described the 47 AMPs it relies on to manage or monitor the aging of passive and long-lived structures and components (SCs).

In LRA Section 3, the applicant provided the results of the AMRs for those SCs identified in LRA Section 2 as within the scope of license renewal and subject to an AMR.

3.0 Applicant's Use of the Generic Aging Lessons Learned Report

In preparing its LRA, the applicant credited NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Revision 1, dated September 2005. 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 period of extended operation. The evaluation results documented in the GALL Report indicate that many of the existing programs are adequate to manage the aging effects for particular SCs for license renewal without change. The GALL Report also contains recommendations on specific areas for which existing programs should be augmented for license renewal. An applicant may reference the GALL Report in its LRA to demonstrate that the programs at its facility correspond to those reviewed and approved in the GALL Report.

The purpose of the GALL Report is to provide the staff with a summary of staff-approved AMPs to manage or monitor the aging of SCs subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources used to review an applicant's LRA will be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report also serves as a reference for applicants and staff reviewers to quickly identify those AMPs and activities that the staff has determined will adequately manage or monitor aging during the period of extended operation.

The GALL Report identifies: (1) systems, structures, and components (SSCs); (2) SC materials; (3) environments to which the SCs are exposed; (4) the aging effects associated with the materials and environments; (5) the AMPs credited with managing or monitoring the aging effects; and (6) recommendations for further applicant evaluations of aging management for certain component types.

The staff performed its review in accordance with the requirements of Title 10, Part 54 of the *Code of Federal Regulations* (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"; the guidance provided in NUREG-1800, "Standard Review

Plan for Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR), Revision 1, dated September 2005; and the guidance provided in the GALL Report.

In addition to its review of the LRA, the staff conducted an onsite audit of selected AMRs and associated AMPs during the week of February 19, 2010, as described in the “Audit Report Regarding the Hope Creek Generating Station, License Renewal Application,” dated September 3, 2010 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML101660452). The onsite audits and reviews are designed to maximize the efficiency of the staff’s LRA review. The applicant can respond to questions, the staff can readily evaluate the applicant’s responses, the need for formal correspondence between the staff and the applicant is reduced, and the result is an improvement in review efficiency.

3.0.1 Format of the License Renewal Application

The applicant submitted an application that followed the standard LRA format, as determined by the staff and the Nuclear Energy Institute (NEI) by letter dated April 7, 2003 (ADAMS Accession No. ML030990052). This LRA format incorporates lessons learned from the staff’s reviews of previous LRAs which used a format developed from information gained during a staff-NEI demonstration project conducted to evaluate the use of the GALL Report in the LRA review process.

The organization of LRA Section 3 parallels Chapter 3 of the SRP-LR. The AMR results information in LRA Section 3 is presented in the following two table types:

(1) Table 3.x.1 – where “3” indicates the LRA section number, “x” indicates the subsection number from the GALL Report, and “1” indicates that this is the first table type in LRA Section 3.

(2) Table 3.x.2-y – where “3” indicates the LRA section number, “x” indicates the subsection number from the GALL Report, “2” indicates that this is the second table type in LRA Section 3, and “y” indicates the system table number.

The content of the previous LRAs and HCGS application are essentially the same. The intent of the format used for the LRA was to modify the tables in LRA Section 3 to provide additional information that would assist the staff in its review. In each Table 1, the applicant summarized the portions of the application that it considered to be consistent with the GALL Report. In each Table 2, the applicant identified the linkage between the scoping and screening results in LRA Section 2 and the AMRs in LRA Section 3.

3.0.1.1 Overview of Table 1s

Each Table 1 summarizes and compares how the facility aligns with the corresponding tables in the GALL Report. The tables are essentially the same as Tables 1 through 6 in the GALL Report, except that the “Type” column has been replaced by an “Item Number” column and the “Item Number in GALL” column has been replaced by a “Discussion” column. The “Item Number” column is a means for the staff reviewer to cross-reference Table 2s with Table 1s. In the “Discussion” column, the applicant provided clarifying information.

The following are examples of information that might be contained within this column:

- further evaluation recommended – information or reference to information on further evaluations
- name of a plant-specific program
- exceptions to GALL Report assumptions
- discussion of how the line is consistent with the corresponding line item in the GALL Report when the consistency may not be obvious
- discussion of how the item is different from the corresponding line item in the GALL Report (e.g., when an exception is taken to a GALL Report AMP)

The format of each Table 1 allows the staff to align a specific row in the table with the corresponding GALL Report table row so that the consistency can be checked easily.

3.0.1.2 Overview of Table 2s

Each Table 2 provides the detailed results of the AMRs for components identified in LRA Section 2 as subject to an AMR. The LRA has a Table 2 for each of the systems or structures within a specific system grouping (e.g., reactor coolant system (RCS), engineered safety features (ESFs), auxiliary systems, etc.). For example, the ESF group has tables specific to the core spray system, high-pressure coolant injection (HPCI) system, and residual heat removal (RHR) system. Each Table 2 consists of nine columns:

(1) Component Type – The first column lists LRA Section 2 component types subject to an AMR in alphabetical order.

(2) Intended Function – The second column identifies the license renewal intended functions, including abbreviations, where applicable, for the listed component types. Definitions and abbreviations of intended functions are in LRA Table 2.0-1.

(3) Material – The third column lists the particular construction material(s) for the component type.

(4) Environment – The fourth column lists the environments to which the component types are exposed. Internal and external service environments are indicated with a list of these environments in LRA Tables 3.0-1 and 3.0-2.

(5) Aging Effect Requiring Management – The fifth column lists aging effects requiring management (AERMs). As part of the AMR process, the applicant determined any AERMs for each combination of material and environment.

(6) Aging Management Programs – The sixth column lists the AMPs that the applicant uses to manage the identified aging effects.

(7) NUREG-1801 Volume 2 Item – The seventh column lists the GALL Report item(s) identified in the LRA as similar to the AMR results. The applicant compared each combination of component type, material, environment, AERM, and AMP in LRA Table 2 with the GALL Report items. If there were no corresponding items in the GALL

Report, the applicant left the column blank in order to identify the AMR results in the LRA tables corresponding to the items in the GALL Report tables.

(8) Table 1 Item – The eighth column lists the corresponding summary item number from LRA Table 1. If the applicant identifies in each LRA Table 2 AMR results consistent with the GALL Report, the Table 1 line item summary number should be listed in LRA Table 2. If there is no corresponding item in the GALL Report, column eight is left blank. In this manner, the information from the two tables can be correlated.

(9) Notes – The ninth column lists the corresponding notes used to identify how the information in each Table 2 aligns with the information in the GALL Report. The notes, identified by letters, were developed by an NEI work group and will be used in future LRAs. Any plant-specific notes identified by numbers provide additional information about the consistency of the line item with the GALL Report.

3.0.2 Staff's Review Process

The staff conducted three types of evaluations of the AMRs and AMPs:

(1) For items that the applicant stated was consistent with the GALL Report, the staff conducted either an audit or a technical review to determine consistency.

(2) For items that the applicant stated was consistent with the GALL Report with exceptions, enhancements, or both, the staff conducted either an audit or a technical review of the item to determine consistency. In addition, the staff conducted either an audit or a technical review of the applicant's technical justifications for the exceptions or the adequacy of the enhancements.

The SRP-LR states that an applicant may take one or more exceptions to specific GALL Report AMP elements; however, any deviation from or exception to the GALL Report AMP should be described and justified. Therefore, the staff considers exceptions as being portions of the GALL Report AMP that the applicant does not intend to implement.

In some cases, an applicant may choose an existing plant program that does not meet all the program elements defined in the GALL Report AMP. However, the applicant may make a commitment to augment the existing program to satisfy the GALL Report AMP prior to the period of extended operation. Therefore, the staff considers these augmentations or additions to be enhancements. Enhancements include, but are not limited to, activities needed to ensure consistency with the GALL Report recommendations. Enhancements may expand, but not reduce, the scope of an AMP.

(3) For other items, the staff conducted a technical review to verify conformance with 10 CFR 54.21(a)(3) requirements.

Staff audits and technical reviews of the applicant's AMPs and AMRs determine whether the aging effects on SCs can be adequately managed to maintain their intended functions consistent with the plant's current licensing basis (CLB) for the period of extended operation, as required by 10 CFR Part 54.

3.0.2.1 Review of AMPs

For AMPs for which the applicant claimed consistency with the GALL Report AMPs, the staff conducted either an audit or a technical review to verify the claim. For each AMP with one or more deviations, the staff evaluated each deviation to determine whether the deviation was acceptable and whether the modified AMP would adequately manage the aging effect(s) for which it was credited. For AMPs not evaluated in the GALL Report, the staff performed a full review to determine their adequacy. The staff evaluated the AMPs against the following 10 program elements defined in SRP-LR Appendix A:

(1) Scope of the Program – Scope of the program should include the specific SCs subject to an AMR for license renewal.

(2) Preventive Actions – Preventive actions should prevent or mitigate aging degradation.

(3) Parameters Monitored or Inspected – Parameters monitored or inspected should be linked to the degradation of the particular structure or component intended functions.

(4) Detection of Aging Effects – Detection of aging effects should occur before there is a loss of structure or component intended functions. This includes aspects such as method or technique (i.e., visual, volumetric, surface inspection), frequency, sample size, data collection, and timing of new/one-time inspections to ensure timely detection of aging effects.

(5) Monitoring and Trending – Monitoring and trending should provide predictability of the extent of degradation, as well as timely corrective or mitigative actions.

(6) Acceptance Criteria – Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the structure or component intended functions are maintained under all CLB design conditions during the period of extended operation.

(7) Corrective Actions – Corrective actions, including root cause determination and prevention of recurrence, should be timely.

(8) Confirmation Process – Confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.

(9) Administrative Controls – Administrative controls should provide for a formal review and approval process.

(10) Operating Experience – Operating experience of the AMP, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support the conclusion that the effects of aging will be adequately managed so that the SC intended functions will be maintained during the period of extended operation.

Details of the staff's audit evaluation of program elements (1) through (6) are documented in SER Section 3.0.3.

The staff reviewed the applicant's quality assurance (QA) program and documented its evaluations in SER Section 3.0.4. The staff's evaluation of the QA program included an assessment of the “corrective actions,” “confirmation process,” and “administrative controls” program elements.

The staff reviewed the information on the “operating experience” program element and documented its evaluation in SER Section 3.0.3.

3.0.2.2 Review of AMR Results

Each LRA Table 2 contains information concerning whether or not the AMRs identified by the applicant align with the GALL Report AMRs. For a given AMR in a Table 2, the staff reviewed the intended function, material, environment, AERM, and AMP combination for a particular system component type. Item numbers in column 7 of the LRA, “NUREG-1801 Volume 2 Item,” correlate to an AMR combination as identified in the GALL Report. The staff also conducted onsite audits to verify these correlations. A blank in column seven indicates that the applicant was unable to identify an appropriate correlation in the GALL Report. The staff also conducted a technical review of combinations not consistent with the GALL Report. The next column, “Table 1 Item,” provides a reference number that indicates the corresponding row in Table 1.

3.0.2.3 UFSAR Supplement

Consistent with the SRP-LR for the AMRs and AMPs that it reviewed, the staff also reviewed the updated final safety analysis report (UFSAR) supplement, which summarizes the applicant’s programs and activities for managing aging effects for the period of extended operation, as required by 10 CFR 54.21(d).

3.0.2.4 Documentation and Documents Reviewed

In its review, the staff used the LRA, LRA supplements, the SRP-LR, and the GALL Report. During the onsite audit, the staff also examined the applicant’s justifications to verify that the applicant’s activities and programs will adequately manage the effects of aging on SCs. The staff also conducted detailed discussions and interviews with the applicant’s license renewal project personnel and others with technical expertise relevant to aging management.

3.0.3 Aging Management Programs

SER Table 3.0.3-1 presents the AMPs credited by the applicant and described in LRA Appendix B. The table also indicates whether the AMP is an existing or new program and the GALL Report AMP with which the applicant claimed consistency and shows the section of this SER in which the staff’s evaluation of the program is documented.

Table 3.0.3-1 Hope Creek Generating Station Aging Management Programs

Applicant Aging Management Program	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report Aging Management Programs	SER Section
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	A.2.1.1 B.2.1.1	Existing	Consistent	XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	3.0.3.1.1
Water Chemistry	A.2.1.2 B.2.1.2	Existing	Consistent with Exceptions	XI.M2, "Water Chemistry"	3.0.3.2.1
Reactor Head Closure Studs	A.2.1.3 B.2.1.3	Existing	Consistent	XI.M3, "Reactor Head Closure Studs"	3.0.3.1.2
BWR Vessel ID Attachment Welds	A.2.1.4 B.2.1.4	Existing	Consistent	XI.M4, "BWR Vessel ID Attachment Welds"	3.0.3.1.3
BWR Feedwater Nozzle	A.2.1.5 B.2.1.5	Existing	Consistent	XI.M5, "BWR Feedwater Nozzle"	3.0.3.1.4
BWR Control Rod Drive Return Line Nozzle	A.2.1.6 B.2.1.6	Existing	Consistent	XI.M6, "BWR Control Rod Drive Return Line Nozzle"	3.0.3.1.5
BWR Stress Corrosion Cracking	A.2.1.7 B.2.1.7	Existing	Consistent with Enhancement	XI.M7, "BWR Stress Corrosion Cracking"	3.0.3.2.2
BWR Penetrations	A.2.1.8 B.2.1.8	Existing	Consistent	XI.M8, "BWR Penetrations"	3.0.3.1.6
BWR Vessel Internals	A.2.1.9 B.2.1.9	Existing	Consistent	XI.M9, "BWR Vessel Internals"	3.0.3.1.7
Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	A.2.1.10 B.2.1.10	New	Consistent	XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)"	3.0.3.1.8
Flow Accelerated Corrosion Program	A.2.1.11 B.2.1.11	Existing	Consistent with Exception	XI.M17, "Flow Accelerated Corrosion"	3.0.3.2.3
Bolting Integrity Program	A.2.1.12 B.2.1.12	Existing	Consistent with Exception and Enhancement	XI.M18, "Bolting Integrity"	3.0.3.2.4
Open-Cycle Cooling Water Program	A.2.1.13 B.2.1.13	Existing	Consistent	XI.M20, "Open-Cycle Cooling Water System"	3.0.3.1.9
Closed-Cycle Cooling Water Program	A.2.1.14 B.2.1.14	Existing	Consistent with Exception and Enhancements	XI.M21, "Closed-Cycle Cooling Water System"	3.0.3.2.5

Applicant Aging Management Program	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report Aging Management Programs	SER Section
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	A.2.1.15 B.2.1.15	Existing	Consistent with Enhancements	XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems"	3.0.3.2.6
Compressed Air Monitoring Program	A.2.1.16 B.2.1.16	Existing	Consistent	XI.M24, "Compressed Air Monitoring"	3.0.3.1.10
Fire Protection Program	A.2.1.17 B.2.1.17	Existing	Consistent with Exception and Enhancements	XI.M26, "Fire Protection"	3.0.3.2.7
Fire Water System	A.2.1.18 B.2.1.18	Existing	Consistent with Enhancements	XI.M27, "Fire Water System"	3.0.3.2.8
Aboveground Steel Tanks	A.2.1.19 B.2.1.19	Existing	Consistent with Enhancements	XI.M29, "Aboveground Steel Tanks"	3.0.3.2.9
Fuel Oil Chemistry	A.2.1.20 B.2.1.20	Existing	Consistent with Exceptions and Enhancements	XI.M30, "Fuel Oil Chemistry"	3.0.3.2.10
Reactor Vessel Surveillance	A.2.1.21 B.2.1.21	Existing	Consistent with Enhancements	XI.M31, "Reactor Vessel Surveillance"	3.0.3.2.11
One-Time Inspection Program	A.2.1.22 B.2.1.22	New	Consistent	XI.M32, "One-Time Inspection"	3.0.3.1.11
Selective Leaching of Materials	A.2.1.23 B.2.1.23	New	Consistent	XI.M33, "Selective Leaching of Materials"	3.0.3.1.12
Buried Piping Inspection	A.2.1.24 B.2.1.24	Existing	Consistent with Enhancement	XI.M34, "Buried Piping and Tanks Inspection"	3.0.3.2.12
External Surfaces Monitoring	A.2.1.25 B.2.1.25	New	Consistent	XI.M36, "External Surfaces Monitoring"	3.0.3.1.13
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	A.2.1.26 B.2.1.26	New	Consistent	XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	3.0.3.1.14
Lubricating Oil Analysis	A.2.1.27 B.2.1.27	Existing	Consistent with Exception	XI.M39, "Lubricating Oil Analysis"	3.0.3.2.13
ASME Section XI, Subsection IWE	A.2.1.28 B.2.1.28	Existing	Consistent with Enhancements	XI.S1, "ASME Section XI, Subsection IWE"	3.0.3.2.14
ASME Section XI, Subsection IWF	A.2.1.29 B.2.1.29	Existing	Consistent	XI.S3, "ASME Section XI, Subsection IWF"	3.0.3.1.15
10 CFR 50, Appendix J	A.2.1.30 B.2.1.30	Existing	Consistent	XI.S4, "10 CFR 50 Appendix J"	3.0.3.1.16
Masonry Wall Program	A.2.1.31 B.2.1.31	Existing	Consistent with Enhancements	XI.S5, "Masonry Wall Program"	3.0.3.2.15

Applicant Aging Management Program	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report Aging Management Programs	SER Section
Structures Monitoring Program	A.2.1.32 B.2.1.32	Existing	Consistent with Enhancements	XI.S6, "Structures Monitoring Program"	3.0.3.2.16
RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"	A.2.1.33 B.2.1.33	Existing	Consistent with Enhancements	XI.S7, RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"	3.0.3.2.17
Protective Coating Monitoring and Maintenance Program	A.2.1.34 B.2.1.34	Existing	Consistent	XI.S8, "Protective Coating Monitoring and Maintenance Program"	3.0.3.1.17
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	A.2.1.35 B.2.1.35	New	Consistent	XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	3.0.3.1.18
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	A.2.1.36 B.2.1.36	New	Consistent	XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"	3.0.3.1.19
Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	A.2.1.37 B.2.1.37	New	Consistent	XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	3.0.3.1.20
Metal Enclosed Bus	A.2.1.38 B.2.1.38	New	Consistent	XI.E4, "Metal Enclosed Bus"	3.0.3.1.21
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	A.2.1.39 B.2.1.39	New	Consistent with Exception	XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	3.0.3.2.18
Metal Fatigue of Reactor Coolant Pressure Boundary	A.3.1.1 B.3.1.1	Existing	Consistent with Enhancements	X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary"	3.0.3.2.19

Applicant Aging Management Program	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report Aging Management Programs	SER Section
Environmental Qualification (EQ) of Electrical Components	A.3.1.2 B.3.1.2	Existing	Consistent	X.E1, “Environmental Qualification (EQ) of Electric Components”	3.0.3.1.22
High Voltage Insulators	A.2.2.1 B.2.2.1	New	Plant-specific	N/A (HCGS High Voltage Insulators Program)	3.0.3.3.1
Periodic Inspection	A.2.2.2 B.2.2.2	New	Plant-specific	N/A (HCGS Periodic Inspection Program)	3.0.3.3.2
Aboveground Non-Steel Tanks	A.2.2.3 B.2.2.3	New	Plant-specific	N/A (HCGS Aboveground Non-Steel Tanks Program)	3.0.3.3.3
Buried Non-Steel Piping Inspection	A.2.2.4 B.2.2.4	Existing	Plant-specific	N/A (HCGS Buried Non-Steel Piping Inspection Program)	3.0.3.3.4
Boral Monitoring Program	A.2.2.5 B.2.2.5	Existing	Plant-specific	N/A (HCGS Boral Monitoring Program)	3.0.3.3.5
Small-Bore Class 1 Piping Inspection	A.2.2.6 B.2.2.6	New	Plant-specific	N/A (HCGS Small-Bore Class 1 Piping Inspection Program)	3.0.3.3.6

3.0.3.1 AMPs That Are Consistent with the GALL Report

In LRA Appendix B, the applicant identified the following AMPs as being consistent with the GALL Report:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Rector Head Closure Studs
- BWR Vessel ID Attachment Welds
- BWR Feedwater Nozzle
- BWR Control Rod Drive Return Line Nozzle
- BWR Penetrations
- BWR Vessel Internals
- Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)

- Open-Cycle Cooling Water System
- Compressed Air Monitoring
- One-Time Inspection
- Selective Leaching of Materials
- External Surfaces Monitoring
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- ASME Section XI, Subsection IWF
- 10 CFR Part 50, Appendix J
- Protective Coating Monitoring and Maintenance Program
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits
- Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Metal Enclosed Bus
- Environmental Qualification (EQ) of Electric Components

3.0.3.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Summary of Technical Information in the Application. LRA Section B.2.1.1 describes the existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program as consistent with GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD." The applicant stated that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program includes inspections performed to manage cracking, loss of fracture toughness, and loss of material in Classes 1, 2, and 3 piping and components exposed to reactor coolant, steam, and treated water environments within the scope of license renewal. The applicant stated that the program provides for periodic visual, surface, and volumetric examination and for leakage testing of pressure retaining piping and components including welds, pump casings, valve bodies, integral attachments, and pressure retaining bolting and that the program consists of condition monitoring activities that detect degradation of components before loss of intended function.

The applicant stated that its current ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is based on the 2001 Edition through the 2003 Addenda of ASME Code Section XI and that its program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code, as specified in 10 CFR 50.55a, 12 months before the start of the inspection interval.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program with the corresponding elements of GALL AMP XI.M1. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.M1, with the exception of the "detection of aging effects" program element. For this element, the staff determined that additional clarification was needed, which resulted in the issuance of a request for additional information (RAI).

The staff noted that the applicant is currently in its third, 10-year inservice inspection (ISI) interval and that the current ISI interval does not continue into the period of extended operation. The staff also noted that during the current interval, the applicant's ISI program includes a risk-informed inservice inspection (RI-ISI) methodology that has been approved for the current interval in accordance with the requirements of 10 CFR 50.55a. The staff further noted that in LRA Section B.2.1.1 the applicant stated that its ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program uses an alternative method to determine the inspection locations, inspection frequency, and inspection techniques for Class 1 Categories B-F and B-J, and Class 2 Categories C-F-1 and C-F-2 welds. It was not clear to the staff whether the discussion of alternative inspection methods in the LRA is applicable only to the current inspection interval or whether the discussion also applies to the period of extended operation. By letter dated May 14, 2010, the staff issued RAI B.2.1.1-01 requesting that the applicant explain why RI-ISI and other alternatives to the requirements of ASME Code Section XI, Subsections IWB, IWC, and IWD are discussed in the LRA's program description for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

In its response dated June 14, 2010, the applicant stated that RI-ISI and other alternatives to the ASME Code Section XI requirements were discussed in the LRA because they are contained in the applicant's existing ISI Program Plan for the third 10-year inspection interval, which was used to evaluate the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program against the recommendations in GALL AMP XI.M1. The applicant stated that it recognizes that the license renewal process does not review and approve future plant ISI program plans, including RI-ISI and other alternatives to the ASME Code Section XI requirements. The applicant further stated that at the end of the current 10-year ISI interval, it will be required to submit an update to its ISI Program Plan for staff review in accordance with the requirements of 10 CFR 50.55a.

Based on its review, the staff finds the applicant's response to RAI B.2.1.1-01 acceptable because it clarifies that the staff's current approval for the use of RI-ISI and other alternatives to ASME Code Section XI requirements is valid only for the current 10-year ISI interval, and it confirms that at the end of the current 10-year ISI interval, the applicant will submit an update to its ISI Program Plan for staff review in accordance with the requirements of 10 CFR 50.55a. The staff's concern as described in RAI B.2.1.1-01 is resolved.

Based on its audit and review of the applicant's response to RAI B.2.1.1-01, the staff finds that elements one through six of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program are consistent with the corresponding program elements of GALL AMP XI.M1 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.1 summarizes operating experience related to the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The applicant described detection of an axially oriented flaw indication on a reactor recirculation inlet nozzle to safe end weld during the 2004 refueling outage and of a circumferentially oriented flaw indication on a different reactor recirculation nozzle to safe end weld during the 2007 refueling outage. For both occurrences, the applicant stated that the characteristics of the flaw were determined, documented, entered into the site's corrective action program, and evaluated both for apparent cause and for determination and implementation of appropriate corrective actions. The applicant stated that these examples demonstrate that the program provides appropriate guidance for inspection and evaluation, deficiencies are entered into the corrective action program, and effective corrective actions, including expansion of inspection scope due to observed conditions, are implemented.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.1 provides the UFSAR supplement for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also notes that the applicant committed (Commitment No. 1) to ongoing implementation of the existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.2 Reactor Head Closure Studs

Summary of Technical Information in the Application. LRA Section B.2.1.3 describes the existing Reactor Head Closure Studs Program as consistent with GALL AMP XI.M3, "Reactor Head Closure Studs." The applicant stated that the program provides for ASME Section XI inspections of reactor head closure studs, nuts, and washers for cracking due to stress-corrosion cracking (SCC) or intergranular stress-corrosion cracking (IGSCC), loss of material due to wear, and coolant leakage from reactor vessel closure stud bolting. The applicant stated that the Reactor Head Closure Studs Program is a condition-based monitoring program that effectively monitors and detects the applicable aging effects and that the frequency of monitoring is adequate to prevent significant degradation. The applicant further stated that the program is based on examination and inspection requirements specified in the 1998 ASME Code Section XI, including the 2000 addenda, and preventive measures described in NRC Regulatory Guide (RG) 1.65, "Materials and Inspection for Reactor Vessel Closure Studs." The applicant also stated that the program uses visual and volumetric examinations in accordance with ASME Code Section XI, the applicable edition of the ASME Code does not require surface examinations of the studs, and surface examinations of the reactor head closure studs are not performed. The applicant stated that the extent and schedule for examining and testing the reactor head closure studs, nuts, and washers are as specified in ASME Code Section XI, Table IWB-2500-1 for Examination Category B-G-1 components, "Pressure Retaining Bolting Greater than 2 Inches in Diameter."

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M3. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.M3, with the exception of the "detection of aging effects" program element. For this program element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

In GALL AMP XI.M3, the "detection of aging effects" program element states that Examination Category B-G-1 for pressure retaining bolting greater than 2 inches in diameter in reactor vessels specifies surface and volumetric examination of studs when they are removed from the reactor vessel flange. In its review of the applicant's "detection of aging effects" program element, the staff noted that the applicant performs volumetric (not volumetric and surface) examination of reactor head closure studs when they are removed from the reactor vessel flange. The staff also noted that in the program description subsection of LRA Section B.2.1.3, the applicant stated that the Reactor Head Closure Studs Program is based on the examination and inspection requirements specified in the 1998 ASME Section XI Boiler and Pressure Vessel (B&PV) Code, Subsection IWB, including the 2000 addenda. However, the staff also noted that this statement conflicts with other statements in the LRA (e.g., LRA Section B.2.1.1), which indicate that the applicant's current ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is based on the 2001 Edition, with 2002 and 2003 Addenda, of ASME Code Section XI.

By letter dated May 14, 2010, the staff issued RAI B.2.1.3-01 requesting that the applicant explain why implementation of only volumetric examinations, rather than volumetric and surface examinations, for removed closure studs was not identified as an exception to the recommendations in the GALL Report and justify how the use of only volumetric inspections for these components will provide adequate detection of aging effects during the period of extended operation. The staff also requested that the applicant clarify which edition and addenda of ASME Code Section XI provide the basis for the applicant's Reactor Head Closure Studs Program.

In its response dated June 14, 2010, the applicant stated that the ASME Code Section XI edition applicable to its current ISI program is the 2001 Edition through 2003 Addenda and that this edition is also applicable to the Reactor Head Closure Studs Program. The applicant further stated that the 1998 Edition of the ASME Code was inadvertently referenced in the Reactor Head Closure Studs Program description in LRA Appendix B. The applicant stated that an exception to the surface examination of the reactor vessel studs described in the "detection of aging effects" program element of GALL AMP XI.M3 was not identified because the program description of GALL AMP XI.M3 states that the ISI requirements are in conformance with the 2001 Edition of the ASME Code Section XI. The applicant also stated that the 2001 Edition of the ASME Code Section XI does not require surface examination of the reactor head closure studs, in place or removed. The applicant further stated that a volumetric examination (only) of the reactor head closure studs is adequate because the 2001 Edition of the ASME Code including the 2003 addenda, in Table IWB-2500-1, Category B-G-1, Item No. B6.20, specifies volumetric examination. In its response, the applicant also stated that its examination in the program is consistent both with the requirements of the applicable ASME Code Section XI and with alternate inspection requirements described in RG 1.65, "Materials and Inspection for Reactor Vessel Closure Studs," Revision 1, dated April 2010.

Based on its review, the staff finds the applicant's response to RAI B.2.1.3-01 acceptable because: (1) the applicant's clarification resolved the conflict noted in the LRA and the ASME Code edition and addenda used by the applicant, which is consistent with the recommendations in the GALL Report, and (2) surface examinations, in addition to volumetric examinations, are not required by the applicable edition and addenda of the ASME Code, and volumetric examinations, alone, have been found adequate to detect the aging effect of interest as documented in the latest revision of RG 1.65. The staff's concern described in RAI B.2.1.3-01 is, therefore, resolved.

Based on its audit and review of the applicant's response to RAI B.2.1.3-01, the staff finds that elements one through six of the applicant's Reactor Head Closure Studs Program are consistent with the corresponding program elements of GALL AMP XI.M3 and, therefore, acceptable.

<u>Operating Experience</u>. LRA Section B.2.1.3 summarizes operating experience related to the Reactor Head Closure Studs Program. The applicant cited the following examples of operating experience. The applicant stated that during the 1995 extended outage (RFO6), all reactor head closure studs and nuts were examined by the ultrasonic testing (UT) method, and during the 1994 refueling outage (RFO5), all reactor head closure studs and nuts were examined by the fluorescent magnetic particle method and all closure washers were examined by the visual testing (VT-1) method. The applicant stated that results of these examinations were all acceptable. The applicant also stated that during the spring 2006 refueling outage (RFO13), all reactor head closure studs were examined by the UT method, and all reactor head closure studs, nuts, and washers were examined by the VT-1 method. The applicant stated that one closure nut (number 66) exhibited gouge marks on the outside of the top surface of the nut and that this condition was identified, documented, and evaluated as acceptable in the corrective action program. The applicant further stated that no other recordable indications were identified

in the inspection. The applicant stated that these examples demonstrate that the Reactor Head Closure Studs Program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant-specific operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion of SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.3 provides the UFSAR supplement for the Reactor Head Closure Studs Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also notes that the applicant committed (Commitment No. 3) to ongoing implementation of the existing Reactor Head Closure Studs Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review of the applicant's Reactor Head Closure Studs Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.3 BWR Vessel ID Attachment Welds

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.4 describes the existing BWR Vessel ID Attachment Welds Program as consistent with GALL AMP XI.M4, "BWR Vessel ID Attachment Welds." The applicant stated that this program manages the effects of cracking of reactor vessel internal attachment welds exposed to reactor coolant through water chemistry and ASME Section XI Inservice Inspection. The applicant further stated that this program incorporates the inspection and evaluation recommendations of Boiling Water Reactor Vessel and Internals Project (BWRVIP)-48-A, as well as the water chemistry recommendations of BWRVIP-130. The applicant stated the scope of the programs includes the steam dryer support and hold down brackets, guide rod wall bracket, feedwater sparger bracket, jet pump riser braces, core spray piping brackets, and surveillance sample holder brackets. The applicant stated that SCC and IGSCC are managed by the detection and sizing

of cracks by ISI in accordance with the guidelines of NRC-approved BWRVIP-48-A and the requirements of the ASME Code Section XI, Table IWB-2500-1.

The applicant stated the jet pump riser brace and core spray piping bracket attachment welds are inspected in accordance with the frequency and methods described in BWRVIP-48-A. The dryer support bracket and feedwater sparger bracket attachment welds are inspected using enhanced visual testing (EVT)-1 techniques while maintaining the inspection frequency per ASME Section XI Examination Category for B-N-2 components. The applicant further stated the remaining attachment welds are inspected in accordance with ASME Code Section XI, Table IWB 2500-1.

<u>Staff Evaluation</u>. During its audit, the staff reviewed the applicant’s claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated. The staff also conducted onsite interviews with the applicant to confirm these results.

The staff compared elements one through six of the applicant’s program to the corresponding elements of GALL AMP XI.M4. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M4.

The staff noted that the applicant’s BWR Vessel ID Attachment Welds Program is based on the augmented inspection and flaw evaluation guideline criteria in BWRVIP-48-A. In the safety evaluation (SE) on Topical Report BWRVIP-48-A, the staff issued three renewal applicant action items for BWR applicants crediting BWRVIP-48-A for aging management of reactor vessel inside diameter (ID) attachment welds. The applicant provided the staff’s renewal applicant action item descriptions and its responses to action items in LRA Appendix C, BWRVIP-All. The three action items follow:

(1) The staff’s first renewal applicant action item required that applicants identify those guideline criteria aspects in BWRVIP-48-A that they might deviate from. The staff noted that the applicant would not deviate from the recommended inspection and flaw evaluation criteria provided in BWRVIP-48-A and, thus, determined that the applicant adequately addressed the staff’s action item.

    Based on this review, the staff concludes that the applicant has adequately addressed the staff’s first renewal applicant action item on BWRVIP-48-A. Therefore, this renewal applicant action item is resolved.

(2) The staff’s second renewal applicant action item required that BWR applicants provide a UFSAR supplement summary description of the AMP based on the BWRVIP-48-A recommended criteria. The applicant stated that LRA Appendix A includes the UFSAR supplement for the BWR Vessel ID Attachment Welds Program. The staff confirmed that the applicant has provided its UFSAR supplement summary description for the BWR Vessel ID Attachment Welds Program in LRA Section A.1.2.9. The staff’s evaluation of the applicant’s UFSAR supplement for this program follows later in this evaluation.

    Based on this review, the staff concludes that the applicant has adequately addressed the staff’s second renewal applicant action item on BWRVIP-48-A. Therefore, this renewal applicant action item is resolved.

(3) The staff's third renewal applicant action item required that BWR applicants ensure that the inspection criteria in BWRVIP-48-A will not conflict with, or result in, changes to the plant's technical specifications (TSs). The applicant stated that its implementation of the inspection strategy in BWRVIP-48-A will not result in the need for any changes to the TS for HCGS. The staff reviewed the TSs for HCGS and confirms that, while the methods in BWRVIP-48-A may constitute alternative staff-approved inspection guidelines for the ASME Code Class 1 reactor vessel ID attachment welds, the TSs for HCGS do not include any requirements to implement the ASME Code Section XI, ISI Program requirements for the facility. The staff also confirms that the applicant's TSs center on operational-based, surveillance-based, and administrative control-based TS requirements and that the ISI Program and requirements are implemented through the applicant's ASME Code Section XI, ISI Program, pursuant to 10 CFR 50.55a. Thus, based on this review, the staff concludes that the applicant has provided an adequate basis for concluding that its implementation of the guidelines in BWRVIP-48-A will not conflict with or result in any necessary changes in the TSs.

Based on this review, the staff concludes that the applicant has adequately addressed the staff's third renewal applicant action item on BWRVIP-48-A. Therefore, this renewal applicant action item is resolved.

Based on its audit, the staff finds that elements one through six of the applicant's BWR Vessel ID Attachment Welds Program are consistent with the corresponding program elements of GALL AMP XI.M4 and, therefore, acceptable.

<u>Operating Experience</u>. LRA Section B.2.1.4 also summarizes operating experience related to the BWR Vessel ID Attachment Welds Program. The staff noted that the applicant provided an overall operating experience summary statement in the "operating experience" program element for the BWR Vessel ID Attachment Weld Program and three examples of HCGS-specific operating experience demonstrating that the AMP accomplishes its intended objective. The staff confirmed that, in the visual inspections (EVT-1, VT-1, VT-3, as applicable) of these welds that have been performed since the plant has been in operation, the HCGS inspections have not detected any cracks in the vessel ID attachment welds. Other, similar BWRVIP-related inspections have found cracks in the core shroud welds and setscrew tack welds. These examples demonstrate that appropriate corrective actions are taken through the corrective action program when deficiencies are found, including actions to determine the cause and extent of the condition.

Based on this review, the staff confirmed that the applicant has been implementing the inspections of its reactor vessel ID attachment welds in accordance with the requirements of ASME Code Section XI, as well as those from BWRVIP-48-A. The staff finds that the applicant's inspection records provide acceptable confirmation that there is no plant-specific operating experience for the reactor vessel ID attachment welds to date.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.4 provides the UFSAR supplement for the BWR Vessel ID Attachment Welds Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also notes that the applicant committed (Commitment No. 4) to ongoing implementation of the existing BWR Vessel ID Attachment Welds Program for managing the aging effects of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's BWR Vessel ID Attachment Welds Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.4 BWR Feedwater Nozzle

Summary of Technical Information in the Application. LRA Section B.2.1.5 describes the existing BWR Feedwater Nozzle Program as consistent with GALL AMP XI.M5, "BWR Feedwater Nozzle." The applicant stated that this program includes enhanced ISI pursuant to ASME Code Section XI, Subsection IWB, Table IWB 2500-1 and the recommendations of report GE-NE-523-A71-0594 and system modifications, performed prior to being put into service, that mitigate cracking.

The applicant stated the program provides for the monitoring of feedwater nozzles for cracking in accordance with the requirements of the ASME Code Section XI, Subsection IWB, Table IWB-2500-1 and recommendations of GE-NE-523-A71-0594-A, Revision 1. The applicant further stated the program is implemented through the plant ISI program and specifies periodic ultrasonic (UT) inspections of critical regions of the feedwater nozzle that are performed at intervals not exceeding 10 years.

The applicant further stated that, in response to NUREG-0619, design changes were made to the feedwater nozzles prior to initial plant operation to mitigate or prevent thermally-induced fatigue cracking, which included eliminating the cladding on nozzle inner diameter and the use of a triple sleeve feedwater sparger design. The applicant further stated that mitigation of cracking in the feedwater nozzle is also accomplished through the use of a feedwater level control system that uses a startup level control valve for low power operation to decrease flow fluctuations, and the reactor water cleanup (RWCU) return flow is injected in both feedwater loops.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated. The staff conducted onsite interviews with the applicant to confirm these results.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M5. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M5. Based on its audit, the staff finds that the applicant's BWR Feedwater Nozzle Program are consistent with the corresponding program elements of GALL AMP XI.M5 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.5 also summarizes operating experience related to the applicant's BWR Feedwater Nozzle Program.

The applicant stated that review of the industry operating experience, as summarized in NUREG-0619, reveals that several BWR plants have experienced cracking in the feedwater nozzles and connecting feedwater spargers. The applicant further stated that NUREG-0619 provided several recommendations for inspections and design improvements. The applicant further stated that, it started operation in 1986 with the important design features recommendations in NUREG-0619 incorporated into the plant's design, including eliminating the cladding on nozzle inner diameter and the use of a low leakage triple sleeve feedwater sparger. The applicant also stated that these design features significantly reduce thermal fatigue and the likelihood of cracking in the feedwater nozzles.

The applicant also stated that the feedwater nozzles have been inspected for cracking as part of the Augmented Inspections of the HCGS ISI program in accordance with NUREG-0619 in 1987, 1992, 1997, and 2004 using UT techniques. The staff reviewed the applicant's operating experience basis document for safety significant operating experience relevant to the aging management of feedwater nozzles. The staff noted that the applicant has conducted numerous inspections of the feedwater nozzles as part of its ISI program without any recordable indications of cracking.

The applicant also provided two operating experience examples that illustrate how cracking has been found in the recirculation system at HCGS. The staff noted that these examples show that industry operating experience is used to improve the effectiveness of the inspection process at HCGS. The staff also noted that these examples demonstrate that whenever deficiencies are found, appropriate corrective actions are taken through the corrective action program, including actions to determine the cause and extent of the condition.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.5 provides the UFSAR supplement for the BWR Feedwater Nozzle Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also notes that the applicant committed (Commitment No. 5) to ongoing implementation of the existing BWR Feedwater Nozzle Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review of the applicant's BWR Feedwater Nozzle Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.5 BWR Control Rod Drive Return Line Nozzle

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.6 describes the existing BWR Control Rod Drive (CRD) Return Line Nozzle Program as consistent with GALL AMP XI.M6, "BWR Control Rod Drive Return Line Nozzle." The applicant stated that the BWR CRD Return Line Nozzle Program monitors the effects of cracking on the intended function of the N9 nozzle (originally intended to be used as the CRD return line nozzle) by performing ISIs in conformance with the ASME Code Section XI, Subsection IWB, Table IWB 2500-1. To mitigate cracking, the applicant capped the CRD return line nozzle prior to going into service in 1986, deleting the return line as part of the original plant design (as outlined in NUREG-0619). The applicant stated that continued inspection of the nozzle as required by NUREG-0619 is not applicable.

The applicant's ISI includes ultrasonic inspections of the nozzle inside radius section and nozzle-to-vessel weld. The applicant stated that future inspections of the inside radius of the N9 nozzle will be performed using EVT-1 in accordance with NRC-accepted Code case N648-1, subject to the conditions specified in RG 1.147.

<u>Staff Evaluation</u>. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated. The staff conducted onsite interviews with the applicant to confirm these results.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M6. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M6.

The staff noted that the applicant made a major system modification that is outlined in NUREG-0619, by capping the CRD return line nozzle. The staff noted that this modification adds the nozzle-to-cap weld to the same category as other welds in the HCGS reactor vessel. The staff noted that the applicant conducts ultrasonic examinations of the CRD return line nozzle-to-cap weld in accordance with the guidelines of staff-approved BWRVIP-75-A as part of the BWR Stress Corrosion Cracking Program. The staff further noted that the inspection methods used in the program have been proven effective in detecting cracking in reactor pressure vessel (RPV) nozzles.

Based on its audit, the staff finds that elements one through six of the applicant's BWR CRD Return Line Nozzle Program are consistent with the corresponding program elements of GALL AMP XI.M6 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.6 also summarizes operating experience related to the BWR CRD Return Line Nozzle Program. The applicant stated that review of the current operating experience reveals that cracking in the CRD return line nozzle has occurred in several BWR plants as delineated in NUREG-0619 and Information Notice (IN) 2004-08, "Reactor Coolant Pressure Boundary Leakage Attributable to Propagation of Cracking in Reactor Vessel Nozzle Welds." In response to the concerns described in NUREG-0619, the HCGS design eliminated the use of a CRD return line. Furthermore, the N9 nozzle, originally intended to be used for the CRD return line, was capped. The applicant believes that these design features significantly reduced the susceptibility of the nozzle to cracking associated with thermal fatigue.

The staff noted that the applicant has conducted numerous UT inspections of the BWR CRD return line nozzle as part of its ISI program without any recordable indications of cracking. The staff further noted that the most recent exam in 2007 was performed using a Performance Demonstration Initiative (PDI)-qualified UT detection technique.

The inspections that the applicant has conducted had been effective in detecting cracking and would have detected cracking if cracking had existed. These flaws or cracking indications are found before loss of intended function. As part of the corrective action program, the corrective action is to repair the flaw with weld overlay. The applicant also provided two operating experience examples that illustrate how flaw or cracking indications have been found in the two similar nozzles at HCGS. These two nozzles were actually recirculation inlet nozzle-to-safe end welds that were inspected as part of the BWR Feedwater Nozzle Program to meet the requirements of Generic Letter (GL) 88-01 and NUREG-0313 for IGSCC. The flaws were detected using an automated Performance Demonstration Initiative (PDI)-qualified UT detection technique. These indications are typical of the degradation previously observed in the industry and described in Section XI.M5 of the GALL Report. These examples show that industry operating experience is used to improve the effectiveness of the inspection process at HCGS. The staff reviewed the corrective action reports associated with these cracks and inspected the two nozzles during the AMP audit. The staff noted that these examples also demonstrate that whenever deficiencies are found, appropriate corrective actions are taken through the corrective action program, including actions to determine the cause and extent of the condition. The applicant further stated that its current ISI activities have been effective in successfully identifying unacceptable indications in other vessel nozzles.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.6 provides the UFSAR supplement for the BWR CRD Return Line Nozzle Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also notes that the applicant committed (Commitment No. 6) to ongoing implementation of the existing BWR CRD Return Line Nozzle Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's BWR CRD Return Line Nozzle Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.6 BWR Penetrations

Summary of Technical Information in the Application. LRA Section B.2.1.8 describes the existing BWR Penetrations Program as consistent with GALL AMP XI.M8, "BWR Penetrations." The applicant stated that the program manages cracking of reactor vessel instrumentation penetrations (nozzles) exposed to reactor coolant by providing for mitigation of cracking through control of water chemistry and ISIs. The applicant also stated that the program includes inspection and flaw evaluation, pursuant to the guidelines of the staff-approved BWRVIP report BWRVIP-49-A, "Instrument Penetration Inspection and Flaw Evaluation Guidelines," and monitoring and control of reactor coolant water chemistry, pursuant to the guidelines of BWRVIP-130, "BWR Water Chemistry Guidelines." The applicant further stated that the scope of the program includes beltline instrumentation nozzles and other instrumentation nozzles, except for the standby liquid control/core plate differential pressure nozzle and the jet pumps instrumentation nozzles, which are in the scope of its ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated. The staff also conducted onsite interviews with the applicant to confirm these results.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M8. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M8.

The staff noted that the applicant's BWR Penetrations Program is based on the augmented inspection and flaw evaluation guideline criteria in BWRVIP-49-A, which includes three renewal applicant action items for BWR applicants crediting BWRVIP-49-A for aging management of reactor vessel instrumentation nozzles. The applicant provided the staff's renewal applicant action item descriptions and its responses to action items in LRA Appendix C, BWRVIP-All (1)-(3). The staff's review of the applicant's three action item responses is as follows:

(1) The staff's first renewal applicant action item required that applicants identify those guideline criteria aspects in BWRVIP-49-A that they might deviate from. The staff noted that the applicant would not deviate from the recommended inspection and flaw evaluation criteria provided in BWRVIP-49-A and; thus, determined that the applicant adequately addressed the staff's action item. Based on this review, the staff concludes that the applicant has adequately addressed the staff's first renewal applicant action item on BWRVIP-49-A. Therefore, this renewal applicant action item is resolved.

(2) The staff's second renewal applicant action item required that BWR applicants provide a UFSAR supplement summary description of the AMP based on the BWRVIP-49-A recommended criteria. The applicant stated that LRA Appendix A includes the UFSAR supplement for the BWR Penetrations Program. The staff confirmed that the applicant has provided its UFSAR supplement summary description for the BWR Penetrations Program in LRA Section A.2.1.8. The staff's evaluation of the applicant's UFSAR supplement for this program follows later in this evaluation. Based on this review, the staff concludes that the applicant has adequately addressed the staff's second renewal applicant action item on BWRVIP-49-A. Therefore, this renewal applicant action item is resolved.

(3) The staff's third renewal applicant action item required that BWR applicants ensure that the inspection criteria in BWRVIP-49-A will not conflict with or result in changes to the plant's TSs. The applicant stated that its implementation of the inspection strategy in BWRVIP-49-A will not result in the need for any changes to the TSs for HCGS. The staff reviewed the TSs for HCGS and confirmed that, while the methods in BWRVIP-49-A may constitute alternative staff-approved inspection guidelines for the reactor vessel instrumentation nozzles, the TSs for HCGS do not include any requirements to implement the ASME Code Section XI, ISI Program requirements for the facility. The staff also confirmed that the applicant's TSs center on operational-based, surveillance-based, and administrative control-based TS requirements and that the ISI program and requirements are implemented through the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, pursuant to 10 CFR 50.55a. Thus, based on this review, the staff concludes that the applicant has provided an adequate basis for concluding that its implementation of the guidelines in BWRVIP-49-A will not conflict with or result in any necessary changes in the TSs. Based on this review, the staff concludes that the applicant has adequately addressed the staff's third renewal applicant action item on BWRVIP-49-A. Therefore, this renewal applicant action item is resolved.

Based on its audit, the staff finds that elements one through six of the applicant's BWR Penetrations Program are consistent with the corresponding program elements of GALL AMP XI.M8 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.8 also summarizes operating experience related to the applicant's BWR Penetrations Program. The applicant stated that its inspection requirements for reactor vessel instrumentation penetrations are implemented as part of the vessel ASME Code Section XI ISI activities, which is consistent with the recommendations of BWRVIP-49-A. The applicant also stated that as required by ASME Code Section XI, at each refueling, a reactor coolant boundary leakage is performed as part of the ISI program. The applicant stated that a VT-2 test by qualified personnel is performed for all reactor coolant pressure retaining components, including the reactor vessel instrument penetrations, within the scope of this program. The applicant further stated that throughout the operating life of the plant, no leaks have been found in the penetrations managed by this program. The applicant stated that a review of the inspection results did not reveal a case in which a VT-2 inspection found cracking in a Class 1 component.

However, the staff noted that the required VT-2 inspections have detected leaks at mechanical interfaces such as flanges and valve packing. The staff further noted that in each case, the discrepancy is entered into the corrective action program and appropriate action, such as repair, is taken. The staff noted that this example demonstrates that the inspection techniques and qualified personnel are capable of detecting small leaks in Class 1 components and demonstrates that the inspection techniques used in the BWR Penetrations Program is capable of detecting leaks before a loss of intended function.

Based on this review, the staff confirmed that the applicant has been implementing the inspections of its reactor vessel instrument nozzles in accordance with the requirements of ASME Code Section XI, as well as those from BWRVIP-49-A. The staff finds that the applicant's inspection records provide acceptable confirmation that there is no plant-specific operating experience for the reactor vessel instrument nozzles to date.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.8 provides the UFSAR supplement for the BWR Penetrations Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also notes that the applicant committed

(Commitment No. 8) to ongoing implementation of the existing BWR Penetrations Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d)

Conclusion. On the basis of the audit and review of the applicant's BWR Penetrations Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.7 BWR Vessel Internals

Summary of Technical Information in the Application. LRA Section B.2.1.9 describes the existing BWR Vessel Internals Program as consistent with GALL AMP XI.M9, "BWR Vessel Internals." The applicant included Appendix C, "Response to BWRVIP Application Action Items," which addresses the staff's license renewal action items for various BWRVIP reports.

The applicant stated that this program includes inspection, flaw evaluation, and repair guidelines that are consistent with the guidelines addressed in relevant BWRVIP reports. The applicant further stated that water chemistry guidelines per the BWRVIP-130 report, "BWR Water Chemistry Guidelines," will be complied with to ensure the integrity of the reactor vessel internals (RVIs) components.

The applicant provided information with respect to plant operating experience in which it stated that inspections were performed on core shroud, core plate, shroud support, low-pressure coolant injection (LPCI) coupling, core spray, jet pumps, top guide, CRD housings, lower plenum, steam dryer, and access hole covers. The applicant further stated that it evaluated the indications that were found thus far in these RVI components and accepted them per the applicable BWRVIP inspection guidelines. The applicant reiterated that it complied with the inspections and flaw evaluation guidelines specified in the applicable BWRVIP reports and it would continue to implement these guidelines to ensure the structural integrity and functionality of these components during the extended period of operation.

Appendix C lists the following BWRVIP reports which would be implemented by the applicant during the period of extended operation:

- BWRVIP-18-A, "BWR Core Spray Inspection and Flaw Guidelines"
- BWRVIP-25, "BWR Core Plate Inspection and Flaw Evaluation Guidelines"
- BWRVIP-26-A, "BWR Top Guide Inspection and Flaw Evaluation Guidelines"
- BWRVIP-38, "BWR Shroud Support Inspection and Flaw Evaluation Guidelines"
- BWRVIP 41, "BWR Vessel and Internals Project, Jet Pump Assembly, Inspection and Flaw Evaluation"

- BWRVIP 42-A, "BWR LPCI Coupling Inspection and Flaw Evaluation Guidelines"
- BWRVIP-47-A, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines"
- BWRVIP-48-A, "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines"
- BWRVIP-49-A, "Instrument Penetration Inspection and Flaw Evaluation Guidelines"
- BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines"

In Appendix C, the applicant included three license renewal action items that are applicable to all BWRVIP reports and several other license renewal action items that are applicable to specific BWRVIP reports. In addition, Appendix C addresses the applicant's response to other license renewal action items.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M9. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M9.

During its audit, the staff reviewed the applicant's program basis document and associated documents, and noted that the applicant's implementation of the BWRVIP reports is consistent with GALL AMP XI.M9. The applicant routinely inspected the RVI components per the applicable BWRVIP reports, and repaired and/or evaluated the indications per the BWRVIP reports or ASME Code Section XI requirements. The staff noted that the applicant's program relies on monitoring and control of reactor water chemistry based on the guidance of BWRVIP-130 report (Electric Power Research Institute (EPRI)-008192), which is a later revision to the BWRVIP-29 report, and the staff finds it acceptable because the GALL Report allows the use of a later revision of the BWRVIP report for monitoring the RCS water chemistry. During the audit, the staff noted that the applicant is using hydrogen water chemistry (HWC) in conjunction with noble metals chemical addition (NMCA) to mitigate IGSCC. The staff also noted that the applicant's methodology of monitoring the effectiveness of HWC/NMCA includes a measurement of the electrochemical corrosion potential (ECP) of the RVI components in RCS water and monitoring the feedwater hydrogen level. These methods will ensure adequate protection of the majority of the RVI components from IGSCC.

During its audit, the staff reviewed several inspection reports associated with the previous inspections that were performed on the RVI components by the applicant. Based on its review, the staff determined that the applicant complied with the inspection requirements of the applicable BWRVIP reports which are consistent with GALL AMP XI.M9. The staff also reviewed the applicant's implementation of its corrective action methodology for identifying nonconforming conditions and found the applicant's corrective action methodology acceptable. The staff, therefore, determined that the applicant adequately implemented the inspection criteria of the BWRVIP reports for the RVI components and that the applicant's program is consistent with GALL AMP XI.M9.

The applicant is required to comply with the license renewal action items specified in the staff's SEs for the aforementioned BWRVIP reports for the period of extended operation. The following paragraphs address the applicant's responses to these license renewal action items and the corresponding staff's evaluation.

License Renewal Action Items Addressed in Appendix C. The applicant made a commitment to comply with the following three license renewal action items which are listed in the staff's SEs for the various BWRVIP reports:

(1) HCGS's AMP for the RVI components is bounded by the aforementioned BWRVIP reports.

(2) The UFSAR supplement addresses a summary of the programs and activities specified in the applicable BWRVIP reports.

(3) HCGS stated that no TS changes have been identified as a result of implementing the AMP for the RVI components.

The staff reviewed the applicant's disposition for these three license renewal action items and concludes that the applicant complied with the intent of the license renewal action items that were specified by the staff in its SEs for the applicable BWRVIP reports.

According to the applicant, there are no time-limited aging analysis (TLAA) issues for HCGS related to the following BWRVIP reports, but it has committed to complying with the requirements specified in these BWRVIP reports:

- BWRVIP-18-A, "BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines"
- BWRVIP-26-A, "BWR Top Guide Inspection and Flaw Evaluation Guidelines"

The staff reviewed the applicant's response to the license renewal action items and accepted it because the staff's SEs for the aforementioned BWRVIP reports do not specify any license renewal action items.

For the license renewal action items specified in the staff's SE dated October 18, 2001, the BWRVIP-74-A report addresses the aging effects on the RVI components and provides requirements to effectively manage the aging effects during the period of extended operation. The BWRVIP-74-A report also addresses the license renewal action items associated with TLAAs for the period of extended operation. The following paragraphs address the TLAAs and the AMP related to RVI components that are specified in the BWRVIP-74-A report, the applicant's responses to these license renewal action items stated in LRA Appendix C, and the corresponding staff's evaluation of each action item response.

Because of item 4 of the staff's BWRVIP-74-A SE report, the applicant identified loss of material and cracking as aging effects that require an AMP for the vessel flange leak detection (VFLD) line. The applicant stated that it would manage these aging effects by performing a one-time inspection and an ISI program per ASME Code Section XI, and by controlling the RCS water chemistry. The staff accepts the applicant's proposed AMP for the VFLD lines because: (1) the combination of ISI and one-time inspection programs will adequately identify the aging degradation in a timely manner, and (2) controlling water chemistry will also enable the applicant to effectively manage the occurrence of any cracking or loss of material in VFLD lines.

Item 5 of the license renewal action items in the staff's SE for the BWRVIP-74-A report requires that the applicant describe how each plant-specific AMP addresses the 10 elements listed in GALL AMP XI.M9. The applicant stated that LRA Appendix B addresses the required 10 elements. The staff reviewed Appendix B and accepts the applicant's response because Appendix B adequately addresses the 10 elements of GALL AMP XI.M9.

Item 6 of the license renewal action items in the staff's SE for the BWRVIP-74-A report requires that the applicant include a water chemistry program in its LRA to ensure that it can effectively manage IGSCC in the RCS. In its response, the applicant stated that it would comply with the BWRVIP-130 report, which superseded the BWRVIP-29 report. The staff accepts this response as the applicant's compliance with the requirements of the BWRVIP-130 provides adequate mitigation to the occurrence of IGSCC.

Item 7 of the license renewal action items in the staff's SE for the BWRVIP-74-A report requires that the applicant identify its RPV surveillance program. The applicant stated that it has implemented the staff-approved BWRVIP integrated surveillance program (ISP)—BWRVIP-116, "BWR Vessel and Internals Project Integrated Surveillance Program." Compliance with the staff-approved ISP enables the applicant to effectively monitor neutron embrittlement of the RPV materials and, therefore, the staff accepts the applicant's response.

Item 8 of the license renewal action items in the staff's SE for the BWRVIP-74-A report requires that the applicant verify that the number of cycles assumed in the original fatigue design is conservative to assure that the estimated fatigue usage for 60 years of plant operation is not underestimated. The use of alternative actions for cases where the estimated fatigue usage is projected to exceed 1.0 will require case-by-case analysis. The applicant should address environmental fatigue for the components listed in the BWRVIP-74 report. The applicant stated that fatigue (including discussions of cycles, projected cumulative usage factors (CUFs), and environmental factors, etc.) is evaluated as a TLAA in LRA Section 4.3. The staff's evaluation on this issue is addressed in SER Section 4.3.

Item 9 of the license renewal action items in the staff's SE for the BWRVIP-74-A report requires that a set of pressure versus temperature (P-T) curves should be developed for the heat-up and cool-down operating conditions in the plant at a given effective full-power year (EFPY) during the period of extended operation. The applicant stated that the development of P-T curves for the period of extended operation is described as a TLAA in LRA Section 4.2.3. The staff evaluated the TLAA associated with P-T curves in SER Section 4.2.

Item 10 of the license renewal action items in the staff's SE for the BWRVIP-74-A report requires that the applicant evaluate the percent of reduction in Charpy upper-shelf energy (USE) values for the beltline materials during the period of extended operation. The applicant stated that the TLAA evaluation of USE is addressed in LRA Section 4.2. The staff evaluated the TLAA associated with USE criteria for the RPV beltline materials in SER Section 4.2.

Item 11 of the license renewal action items in the staff's SE for the BWRVIP-74-A report requires that the applicant obtain relief from the ISI of the circumferential shell welds during the period of extended operation. The BWRVIP-05 report, "Reactor Vessel Shell Weld Inspection Guidelines," requires that each licensee will have to demonstrate that: (1) at the end of the period of extended operation, the circumferential shell welds will satisfy the limiting conditional failure frequency specified in Appendix E for the staff's SE dated July 28, 1998, for the BWRVIP-05 report and (2) it has implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the staff's SE dated July 28, 1998, for the BWRVIP-05 report. The applicant stated that the discussion of the relief from the ISI of the circumferential shell welds for HCGS during the period of extended operation is described in LRA Section 4.2. The staff evaluated the TLAA associated with the relief from the ISI of the RPV circumferential shell welds for HCGS and the staff's evaluation is addressed in SER Section 4.2.

Item 12 of the license renewal action items in the staff's SE for the BWRVIP-74-A report requires that the applicant monitor RPV axial beltline weld embrittlement. One acceptable method is to determine that the mean reference temperature nil-ductility transition (RT_{NDT}) of the limiting RPV axial beltline weld at the end of the period of extended operation is less than the values specified in Table 1 of the staff's SE dated October 18, 2001, for the BWRVIP-74-A report. The applicant stated that the TLAA evaluation of beltline axial welds is addressed in LRA Section 4.2. The staff evaluated the TLAA associated with the RPV axial weld failure probability for HCGS in SER Section 4.2.

Item 13 of the license renewal action items in the staff's SE for the BWRVIP-74-A report requires that the Charpy USE, P-T limit, inspection relief for the RPV circumferential shell welds, and RPV axial weld integrity evaluations are all dependent upon the neutron fluence. The applicant may perform neutron fluence calculations using a staff-approved methodology or may submit its methodology for staff review. If the applicant performs the neutron fluence calculation using a methodology previously approved by the staff, the applicant should identify the staff letter that approved the methodology. The applicant stated that the calculation of neutron flux is addressed in LRA Section 4.2. The staff evaluated the TLAAs associated with the neutron fluence calculations in SER Section 4.2.

ASME Code Section XI, Subsection IWB-3600 states that flaw indications that exceed the size of allowable indications defined in ASME Code Section XI, Subsection IWB-3500 may be evaluated by analytical procedures, such as described in ASME Code Section XI, Appendix A, in order to calculate growth until the next inspection or the end of service lifetime of the component. Item 14 of the license renewal action items in the staff's SE for the BWRVIP-74-A report requires that the components that have indications which were previously evaluated analytically in accordance with ASME Code Section XI, Subsection IWB-3600 until the end of the 40-year service period shall be re-evaluated for the 60-year service period corresponding to the license renewal term. The applicant stated that up to the time of the issuance of the staff's SE for the BWRVIP-74-A report, it has no flaws that exceeded the applicable acceptance standards of ASME Code Section XI, Subsection IWB-3500 that would merit an analytical evaluation in accordance with ASME Code Section XI, Subsection IWB-3600. Therefore, item 14 is not applicable because there are no indications that require a re-evaluation for the period of extended operation. The staff accepts this response because there are no flaws that require an analytical re-evaluation performed in accordance with ASME Code Section XI, Subsection IWB-3600.

Based on its review, the staff finds that the applicant has addressed the license renewal action items as described above, and the staff's acceptance of each license renewal action item is described above or in the referred SER Section 4.

Based on its audit, the staff finds that elements one through six of the applicant's BWR Vessel Internals Program are consistent with the corresponding program elements of GALL AMP XI.M9 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.9 summarizes operating experience related to the BWR Vessel Internals Program. The staff noted that the applicant has identified relevant HCGS-specific operating experience in the "operating experience" program element discussion for the BWR Vessel Internals Program. The staff noted that there were flaw indications (cracks) in the core shroud circumferential welds and some of the jet pump assembly components (i.e., jet pump set screw tack weld and sensing line brackets). The staff also noted that the applicant has dispositioned the core shroud weld flaw indications as acceptable for further service without the need for repair or replacement of the components at this time. The staff noted that an auxiliary spring wedge was installed to replace the function of the set screw and the sensing line brackets were repaired.

Related to the extended power uprate (EPU) at HCGS, the applicant has also implemented additional inspections on steam dryer components according to the guidance in BWRVIP-139. The staff noted that the inspections identified some additional SCC and weld quality cracking, but there was no evidence of the fatigue cracking that has been found in other BWRs after EPU. The applicant has attributed the lack of fatigue cracking to modifications made to the steam dryer as a result of industry experience.

The staff noted that by implementing the BWR Vessel Internals Program, the applicant adequately demonstrated its capability in identifying the aging effects associated with the RVI components and that it can adequately monitor the aging degradation of the RVI components by using proper corrective actions to restore the structural integrity of the RVI components.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.9 provides the UFSAR supplement for the BWR Vessel Internals Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2.

The staff also notes that the applicant committed (Commitment No. 9) to ongoing implementation of the existing BWR Vessel Internals Program for managing aging of applicable components during the period of extended operation and to implement the BWRVIP guidelines as follows:

- PSEG will inform the staff of any decision to not fully implement a BWRVIP guideline approved by the staff.
- PSEG will notify the staff if changes are made to the RPV and its internals programs that affect the implementation of the BWRVIP guideline.
- PSEG will submit any deviation from the existing flaw evaluation guidelines that are specified in the BWRVIP guideline.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's BWR Vessel Internals Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.8 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)

Summary of Technical Information in the Application. LRA Section B.2.1.10 describes the new Thermal Aging and Neutron Irradiation Embrittlement of CASS Program as consistent with GALL AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)."

The applicant stated that its program will include a component-specific evaluation to: (a) identify the "susceptible components" determined to be limiting from the standpoint of thermal aging susceptibility and/or neutron irradiation embrittlement, and (b) for each "potentially susceptible" component, aging management will be accomplished through either a supplemental examination of the affected component based on the neutron fluence to which the component has been exposed as part of the BWR Vessel Internals Program during the period of extended operation, or a component-specific evaluation to determine its susceptibility to loss of fracture toughness.

The applicant identified the following CASS components as susceptible to thermal aging and neutron irradiation embrittlement and subject to loss of fracture toughness: control rod assemblies, guide tubes, core spray lines and spargers, spray nozzles and elbows, fuel supports, jet pump assemblies, transition piece, inlet, throat, and diffuser collar, and steam dryers drain line fittings. The applicant also stated that the new program will be implemented prior to the period of extended operation.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP X1.M13. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M13.

The staff also conducted onsite interviews with the applicant to confirm the plan for the new program. In addition, the staff also confirmed that this program will include two phases where:

- Phase 1 will identify components that exceed neutron fluence (E>10^{17} neutrons per square centimeter (n/cm^2) for all neutrons with E>1 million electron volts (MeV)) and/or temperature (greater than 250 °C) limits.

- Phase 2 will either recommend supplemental examinations of susceptible components during the period of extended operation, or a component-specific evaluation to determine the component's susceptibility to loss of fracture toughness.

Based on its audit, the staff finds that elements one through six of the applicant's Thermal Aging and Neutron Irradiation Embrittlement of CASS Program are consistent with the corresponding program elements of GALL AMP XI.M13 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.10 also summarizes operating experience related to the applicant's existing BWR Vessel Internals Program. The applicant stated that there is sufficient confidence that the implementation of the Thermal Aging and Neutron Irradiation Embrittlement of CASS Program, which will augment the existing BWR Vessel Internals Program, will effectively identify the degradation of the CASS components found in the control rod assemblies, core spray lines and spargers, fuel supports, jet pump assemblies, and in the steam dryer prior to failure.

The staff reviewed the applicant's operating experience basis document for safety-significant operating experience relevant to the aging management of CASS components. The staff noted that the applicant has conducted numerous inspections of the reactor internals as part of its BWR Vessel Internals Program and provided three examples of aging that have been detected. The staff noted that in each case, inspections done as part of the existing BWR Vessel Internals Program found evidence of aging and conducted component-specific evaluations to determine whether the component should be repaired, replaced, or put on an enhanced inspection schedule. The staff noted that these examples, along with interviews with the applicant, demonstrate that the new program will: (1) implement appropriate corrective actions when deficiencies are identified and taken through the corrective action program, including actions to determine the cause and extent of condition, and (2) utilize operating experience to improve the inspection process at HCGS and ensure that the intended safety function of susceptible components is maintained.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. The staff noted that this is a new program and that no plant-specific operating experience is available. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.10 provides the UFSAR supplement for the Thermal Aging and Neutron Irradiation Embrittlement of CASS Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also notes that the applicant committed (Commitment No. 10) to implement the new Thermal Aging and Neutron Irradiation Embrittlement of CASS Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review of the applicant's Thermal Aging and Neutron Irradiation Embrittlement of CASS Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.9 Open-Cycle Cooling Water System

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.13 describes the existing Open-Cycle Cooling Water System Program as consistent with GALL AMP XI.M20, "Open-Cycle Cooling Water System." The applicant stated that its program includes surveillance and control techniques to manage aging effects caused by bio-fouling, corrosion, erosion, protective coating failures, and silting in the open-cycle cooling water system. The applicant also stated that the program provides assurance that cracking, loss of material, increase in porosity and permeability, loss of strength, hardening, and reduction of heat transfer are maintained at acceptable levels. The applicant further stated that sodium hypochlorite injection, system and component testing, visual inspections, and other nondestructive examinations (NDEs) are performed to ensure that aging effects are managed.

<u>Staff Evaluation</u>. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M20. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M20. Based on its audit, the staff finds that elements one through six of the applicant's Open-Cycle Cooling Water System Program are consistent with the corresponding program elements of GALL AMP XI.M20 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.13 summarizes operating experience related to the Open-Cycle Cooling Water System Program. The applicant stated in the operating experience that it identified excessive corrosion at several of the bell and spigot joints in portions of the service water buried piping. As a consequence, the applicant inspected all similar joints in the system using broadband scanning, which can detect degradation of carbon steel piping enclosed in reinforced concrete. Based on operating experience from the Salem Nuclear Generating Station (Salem) (co-located with HCGS), the applicant also stated that WEKO (elastomer) seals were used to correct the problem on eight joints, and cleaning and coating restorations were performed to restore other joints to original configurations.

The applicant stated in operating experience that during routine maintenance, it identified three locations in the service water piping header that were below the nominal piping thickness where an epoxy coating had worn away. The applicant also stated that further evaluations of wall thickness were performed, and it was determined that the thicknesses were greater than the calculated design minimum wall thickness so the locations were cleaned and recoated with epoxy. The applicant further stated that a subsequent inspection of the system identified an additional area that had corroded below the minimum wall thickness and that corrective actions were taken to repair that area by using weld buildup and recoating with epoxy.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.13 provides the UFSAR supplement for the Open-Cycle Cooling Water System Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.2-2, 3.3-2, and 3.4-2. The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The staff also notes that the applicant committed (Commitment No. 13) to ongoing implementation of the existing Open-Cycle Cooling Water System Program for managing aging of applicable components during the period of extended operation.

Conclusion. On the basis of its review of the applicant's Open-Cycle Cooling Water System Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.10 Compressed Air Monitoring

Summary of Technical Information in the Application. LRA Section B.2.1.16 describes the existing Compressed Air Monitoring Program as consistent with GALL AMP XI.M24, “Compressed Air Monitoring.” The applicant stated that the program consists of testing, monitoring, and inspection of piping, piping components, and piping elements, compressor housings, and tanks for loss of material due to general, pitting, and crevice corrosion in the compressed air systems. The applicant also stated that this program includes periodic leak testing of valves, piping, and other system components; and preventive monitoring that checks air quality at multiple locations in the system to ensure that oil, water, rust, dirt, and other contaminants are kept within accepted limits. The applicant further stated that the program provides for timely corrective actions to ensure that the system is operated within accepted limits.

Staff Evaluation. During its audit, the staff reviewed the applicant’s claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant’s program to the corresponding elements of GALL AMP XI.M24. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M24. Based on its audit, the staff finds that elements one through six of the applicant’s Compressed Air Monitoring Program are consistent with the corresponding program elements of GALL AMP XI.M24 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.16 summarizes operating experience related to the Compressed Air Monitoring Program. The applicant stated that the program is effective in ensuring that intended functions will be maintained consistent with the CLB for the period of extended operation. The applicant also stated that it had found and replaced instrument air lines that were worn due to vibration at mounting points. The applicant further stated that rust particles were found in the aftercooler drain line and drain trap, clogging the drain trap and thereby causing it to fail; these were replaced and UT testing was performed on upstream components to identify the potential source of rust particles. In both of these operational experiences, the applicant identified that through its actions, identification, evaluation, and correction, it ensured the continued effective operation of the compressed air monitoring system.

Furthermore, the applicant stated that it identified a leak in an instrument airline at an elbow joint on the exit of an air dryer. The applicant stated that a temporary repair was made, and the item was placed into the work management system. The applicant also stated this temporary repair was completed because an instrument air header outage was required for a permanent repair to be made and that it was scheduled for completion during a refueling outage. The applicant further stated that this was an example of how compressed air deficiencies were identified, evaluated, and corrected to ensure the system maintained its intended functions.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.16 provides the UFSAR supplement for the Compressed Air Monitoring Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.3-2. The staff also notes that the applicant committed (Commitment No. 16) to ongoing implementation of the existing Compressed Air Monitoring Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Compressed Air Monitoring Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.11 One-Time Inspection

Summary of Technical Information in the Application. LRA Section B.2.1.22 describes the applicant's new One-Time Inspection Program as consistent with GALL AMP XI.M32, "One Time Inspection." The applicant stated that the One-Time Inspection Program will provide reasonable assurance that an aging effect is not occurring, or that the aging effect is occurring slowly enough to not affect the components intended function during the period of extended operation and, therefore, will not require additional aging management. The applicant stated that major component types covered by the program include piping, piping elements and piping components, reactor vessel and nozzles, and heat exchangers and tanks. The applicant further stated that the One-Time Inspection Program will be used to confirm the effectiveness of the Water Chemistry, Fuel Oil Chemistry, and Lubricating Oil Analysis programs at mitigating the effects of aging. The applicant further stated that it will use visual and volumetric inspection techniques performed per ASME Code standards, and its acceptance criteria will follow station procedures based on applicable industry and regulatory codes and standards.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M32 and confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.M32, with the exception of the "detection of aging effects" program element. For this element, the staff determined a need for additional clarification, which resulted in the issuance of an RAI.

GALL AMP XI.M32 states in the "detection of aging effects" program element that, "the inspection includes a representative sample of the system population, and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin." The LRA states, in regard to "detection of aging effects," that the program element includes: (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience and (b) identification of inspection locations in the system, component, or structure based on the aging effect. The LRA, however, did not state how the selected set of sample components would be determined or the size of the sample of components that would be inspected. The staff noted that due to the uncertainty in determining the most susceptible locations and the potential for aging to occur in other locations, large sample sizes may be required in order to adequately confirm that an aging effect is not occurring. By letter dated December 13, 2010, the staff issued RAI B.2.1.22-1 requesting that the applicant provide clarifying information regarding how the selected set of components to be sampled will be determined and to provide the size of the sample of components that will be inspected.

In its response dated January 6, 2011, the applicant stated that it will develop a sample plan which will establish sample groups based on aging effects and environments and be populated with the components and their materials of fabrication. The applicant also stated that a sample size of 20 percent of the population (up to a maximum of 25 inspections) will be established for each sample group. The applicant further stated that the selection of components for inspection, when possible, will be biased toward inspecting bounding or lead components most susceptible to aging in potentially more aggressive environments (e.g., low or stagnant flow areas) and selecting components with the lowest design margin. The applicant revised the program's UFSAR supplement and program description to include this information. The staff finds the applicant's response acceptable because the applicant's sampling methodology: (a) ensures a representative sample of material and environment combination is considered, (b) ensures sample locations will focus on the most susceptible components, and (c) includes an appropriate sample size. The staff's concerns described in RAI B.2.1.22-1 are resolved.

Based on its audit and the resolution to RAI B.2.1.22-1, the staff finds that elements one through six of the applicant's One-Time Inspection Program are consistent with the corresponding program elements of GALL AMP XI.M32 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.22 summarizes operating experience related to the One-Time Inspection Program. The applicant stated several examples of inspection that demonstrate that it has successfully used visual and volumetric inspection techniques to evaluate the integrity of various components, including the reactor steam dryer assembly weldments, service water pump lubrication reservoirs, and steam supply nozzle pipes at the feedwater heater. The applicant also stated that it will apply the same techniques in its

One-Time Inspection Program and, therefore, the program will be as effective as its previous inspections in identifying aging effects in relevant systems and components. In addition, for systems that credit the One-Time Inspection Program for aging management, the applicant reviewed Maintenance Rule and System Health reports and identified that none of the aging effects being managed by the One-Time Inspection Program negatively impacts any of those systems' performance or causes any loss of component intended function for these systems. The applicant further stated that the overall condition of these systems with respect to the applicable aging effects, coupled with the one-time inspections, provide sufficient confidence that implementation of the One-Time Inspection Program will effectively identify and manage degradation that could lead to failure.

The staff reviewed operating experience information in the application during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.22 provides the UFSAR supplement, as amended by letter dated January 6, 2011, for the One-Time Inspection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.1-2, 3.2-2, 3.3-2, and 3.4-2. The staff also notes that the applicant committed (Commitment No. 22) to implement the new One-time Inspection Program prior to entering the period of extended operation for managing aging of applicable components. Specifically, the applicant committed:

1. To confirm the effectiveness of the Water Chemistry program to manage the loss of material, cracking, and the reduction of heat transfer aging effects for aluminum, copper alloy, ductile cast iron, gray cast iron, nickel alloy, steel, stainless steel, and cast austenitic stainless steel in treated water, steam, sodium pentaborate and reactor coolant environments.

2. To confirm the effectiveness of the Fuel Oil Chemistry program to manage the loss of material aging effect for copper alloy, steel, galvanized steel and stainless steel in a fuel oil environment.

3. To confirm the effectiveness of the Lubricating Oil Analysis program to manage the loss of material and the reduction of heat transfer aging effects for copper alloy, gray cast iron, steel and stainless steel in a lubricating oil environment.

4. To confirm loss of material in carbon steel piping and fitting is insignificant in an air/gas-wetted (internal) environment.

The sample plan for inspection associated with the One-Time Inspection program will be developed to ensure there are adequate inspections to address each of the material, environment, and aging effect combinations. A sample size of 20 percent of the population (up to a maximum of 25 inspections) will be established for each of the sample groups.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's One-Time Inspection Program and the resolution to RAI B.2.1.22-1, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement, as amended, for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.12 Selective Leaching of Materials

Summary of Technical Information in the Application. LRA Section B.2.1.23 describes the new Selective Leaching of Materials Program as consistent with GALL AMP XI.M33, "Selective Leaching of Materials." The applicant stated that the Selective Leaching of Materials Program ensures the integrity of components made of gray cast iron, copper alloy with greater than 15 percent zinc, and aluminum bronze with greater than 8 percent aluminum exposed to raw water, closed cooling water, soil (ground water), or treated water that may lead to selective leaching of one of the metal components. The applicant also stated that the AMP includes a one-time visual inspection and hardness measurements of selected components that may be susceptible to selective leaching to identify whether material loss from selective leaching is occurring and if selective leaching will affect the ability of components to perform their intended function for the period of extended operation.

Based upon an observation during the regional license renewal inspections, IP-71002 (ADAMS Accession No. ML102740350), the applicant amended its LRA by letter dated September 1, 2010, to include aging management activities, such as periodic inspections and trending, to manage the aging effects for material and environment combinations where selective leaching is identified.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M33 and confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.M33, with the exception of the "scope of the program" element. For this element, the staff determined a need for additional clarification via an RAI.

GALL AMP XI.M33 states in the "scope of the program" element that the program "includes a one-time visual inspection and hardness measurement of a selected set of sample components to determine whether loss of material due to selective leaching is not occurring for the period of extended operation." The LRA did not state how the selected set of sample components would be determined or the size of the sample of components that would be inspected. The staff noted that due to the uncertainty in determining the most susceptible locations and the potential for aging to occur in other locations, large sample sizes may be required in order to adequately confirm that selective leaching is not occurring. By letter dated December 13, 2010, the staff issued RAI B.2.1.23-1 requesting that the applicant provide specific information regarding how the selected set of components to be sampled will be determined and to provide the size of the sample of components that will be inspected.

In its response dated January 6, 2011, the applicant stated that the sample size and inspection locations for the one-time inspections will be developed to ensure that a representative sample of material and environment combinations is selected with a focus on the leading indicator components. The applicant also stated that the representative sample size and one-time inspection locations will be based on the population of components with the two susceptible materials of fabrication. The applicant further stated that a sample size of 20 percent of the population of copper alloy components susceptible to selective leaching and a sample size of 20 percent of the population of gray cast iron components susceptible to selective leaching will be established with up to a maximum of 25 inspections performed per susceptible material group. The applicant revised the program's UFSAR supplement and program description to include this information. The staff finds the applicant's response acceptable because the applicant's sampling methodology: (a) ensures a representative sample of material and environment combinations is considered, (b) ensures sample locations will focus on known susceptible components, and (c) includes an appropriate sample size. The staff's concerns described in RAI B.2.1.23-1 are resolved.

Based on the results of the audit and the resolution of RAI B.2.1.23-1, the staff finds that elements one through six of the applicant's Selective Leaching of Materials Program are consistent with the corresponding program elements of GALL AMP XI.M33 and, therefore, acceptable.

<u>Operating Experience</u>. LRA Section B.2.1.23 summarizes operating experience related to the Selective Leaching of Materials Program. The applicant stated that through visual inspection, it has identified de-alloying of aluminum bronze valves in the service water system brackish water environment. The applicant also stated that a sample of a cross section of a valve was sent to a laboratory for confirmation of selective leaching and assessment of material properties, and that the service water system aluminum bronze valves susceptible to de-alloying were placed into the Valve Material Condition Improvement Project. The applicant further stated that as part of this project, valves that are susceptible to selective leaching have been gradually replaced and that this operating experience is being used to assess the potential for selective leaching and to proactively replace valves susceptible to selective leaching.

The applicant stated that it has identified the graphitization of gray cast iron submerged pump components from long-term immersion in saltwater and brackish water environments in the Salem plant (co-located with the HCGS). The applicant also stated that as a result of this operating experience, HCGS evaluated similar potentially affected components and that while similar materials, environments, and components exist at HCGS, graphitization had not been observed at the plant. The applicant further stated that the HCGS pumps are less susceptible to selective leaching due to the water being recirculated as a closed-loop treated water system through the cooling tower, rather than straight from the river, and because of the concern for selective leaching, these components are inspected on a 6-year frequency to ensure their function will be maintained. The applicant stated that this operating experience demonstrates how it effectively incorporates operating experience at Salem to assess the applicability at HCGS for potential selective leaching.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.23 provides the UFSAR supplement, as amended by letter dated January 6, 2011, for the Selective Leaching of Materials Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.1-2, 3.2-2, and 3.3-2. The staff also notes that the applicant committed (Commitment No. 23) to implement the new Selective Leaching of Materials Program prior to entering the period of extended operation for managing aging of applicable components. Specifically, the applicant's commitment states:

> Selective Leaching of Materials is a new program that will include one-time inspections of a representative sample of susceptible components to determine where loss of material due to selective leaching is occurring. A sample size of 20 percent of susceptible components will be subjected to a one-time inspection with a maximum of 25 inspections for each of the susceptible material groups. Where selective leaching is identified, further aging management activities will be implemented such that the component intended function is maintained consistent with the current licensing basis through the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Selective Leaching of Materials Program and resolution of RAI B.2.1.23-1, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement, as amended, for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.13 External Surfaces Monitoring

Summary of Technical Information in the Application. LRA Section B.2.1.25 describes the new External Surfaces Monitoring Program as consistent with the program elements in GALL AMP XI.M36, "External Surfaces Monitoring." The applicant stated that its program is a condition monitoring program that relies on observations made during visual inspections. The applicant also stated that it relies on this program to preliminarily detect corrosion by inspecting for degradation of coatings and the appearance of visually apparent corrosion products on steel components. The applicant further stated that the visual inspections conducted within this program serve to detect degradation of steel components prior to any loss of intended function.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M36. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M36. Based on its audit, the staff finds that elements one through six of the applicant's External Surfaces Monitoring Program are consistent with the corresponding program elements of GALL AMP XI.M36 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.25 summarizes operating experience related to the External Surfaces Monitoring Program. The applicant's operating experience included accounts of the detection and assessment of corrosion on steel piping surfaces and the corrective actions. The corrective actions, as described by the applicant, included removal of corrosion products prior to repair of the affected area by repainting.

In one instance of operating experience, the applicant described a case where, during a plant tour, rust was observed on two chilled water pipe flanges that were exposed by the removal of insulation to facilitate piping repair on a section of chilled water supply line. The applicant stated that an engineering analysis determined that the corrosion was due to condensation that was allowed to form on the exposed area due to removal of the insulation. The applicant also stated that the program was effective for detecting the corrosion before loss of functionality and that the knowledge gained in that instance of operating experience was used to increase operator awareness regarding the potential susceptibility of the chilled water line to corrosion when insulation is not in place.

Through another example of operating experience, the applicant described the detection of rust due to a leaking reactor core isolation cooling valve. The applicant stated that the observation of the rust, which led to the detection of the leak, illustrated the effectiveness of the program's inspection process. The applicant also described the corrective actions that were implemented, which involved repairing the affected area that had rusted and also repairing the leak.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of corrosion on SCCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.25 provides the UFSAR supplement for the External Surfaces Monitoring Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.2-2, 3.3-2, and 3.4-2. The staff also notes that the applicant committed (Commitment No. 25) to implement the new External Surfaces Monitoring Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review of the applicant's External Surfaces Monitoring Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.14 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.26 describes the new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program as consistent with GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The applicant stated that this program manages the internal surfaces of steel piping, piping components, piping elements, tanks, and ducting components for loss of material. The applicant also stated that this program includes provisions for visual inspections of the internal surfaces of components not managed under other AMPs and that inspections will be performed when internal surfaces are accessible during maintenance, surveillances, and scheduled outages. For painted or coated surfaces, the applicant stated that it will monitor the condition of the finish as an indicator for corrosion of the underlying steel. The applicant further stated that operating history will be taken into consideration to determine the frequency of inspections and that a representative sample of locations will also be taken into consideration.

<u>Staff Evaluation</u>. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M38. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M38, with the exception of the “detection of aging effects” program element.

When the staff compared the LRA program description, which suggests the use of a “representative sample,” to GALL AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” “detection of aging effects” program element recommendations on sampling, it was unclear to the staff how the applicant defined its “representative sample” (i.e., the population criteria, size, and sampling methodology used).

On August 18, 2010, the staff held a telephone conference with the applicant (see ADAMS Accession No. ML102440706) to clarify the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program’s sampling methodology, including how the population for each of the material-environment-aging effect combinations is being selected, and what type of engineering, design, or operating experience considerations would be used to select the sample of components for both the scheduled and supplemental inspections. During this discussion, the applicant stated that the program will ensure that for each material, environment, and aging effect combination, the applicant will conduct representative inspections as directed by formal preventive maintenance or recurring tasks within the work management system. The applicant also stated that the intent is to use existing preventive maintenance or recurring task activities augmented with new recurring task activities to address inspection of material, environments, and aging effects not adequately addressed by the current activities. The applicant further stated that if adverse conditions are identified, they will be entered into a corrective action program, discussed in the LRA, and appropriate actions will be directed including identifying and evaluating the cause and extent of condition(s). The staff finds the applicant’s response acceptable and that the “detection of aging effects” program element is consistent with the corresponding element of GALL AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” because its “representative sample” will include inspections for each material, environment, and aging effect combinations and that when degradation is found, it will be entered in the corrective action program.

Based on its audit, the staff finds that elements one through six of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program are consistent with the corresponding program elements of GALL AMP XI.M38 and, therefore, acceptable.

<u>Operating Experience</u>. LRA Section B.2.1.26 summarizes operating experience related to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The applicant stated that industry operating experience indicates that it is possible to sustain age degradation on internal surfaces of susceptible components, but that visual inspections of internal surfaces of components at the plant showed only minimal internal degradations. The applicant also stated the following four examples of plant operating experience which demonstrate the effectiveness of the relevant plant procedures on maintenance, inspections, walkdowns, and systems checks:

(1) An extensive maintenance history search and interviews with system managers for the ventilation systems that are within the scope of license renewal was performed and revealed no evidence of age-related degradation.

(2) Review of the 10-year inspection of the HPCI pumps, including NDE data, identified no evidence of degradation.

(3) During a walkdown of the service water intake structure, a through wall leak was identified that was attributed to silt accumulation and corrosion on the interior of the affected piping. The affected piping was replaced satisfactorily.

(4) During system testing, a check valve in the HPCI system was discovered to be leaking past the seat. The leakage was attributed to build up of corrosion products, and the seat was repaired and returned to service satisfactorily.

The applicant further stated that these examples provide objective evidence that existing plant activities identify nonsafety-related failures prior to significant impact on adjacent safety-related SSCs and that identified failures are evaluated and corrective actions are taken to preclude recurrence.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.26 provides the UFSAR supplement for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.2-2, 3.3-2, and 3.4-2. The staff also notes that the applicant committed (Commitment No. 26) to implement the new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.15 ASME Section XI, Subsection IWF

Summary of Technical Information in the Application. LRA Section B.2.1.29 describes the existing ASME Section XI, Subsection IWF Program as consistent with GALL AMP XI.S3, "ASME Section XI, Subsection IWF." The applicant's ASME Section XI, Subsection IWF Program consists of periodic ISI including visual examination of Classes 1, 2, 3, and metal containment (MC) component supports. They are inspected for loss of material, and loss of mechanical function in indoor air, outdoor air, and treated water environments. Bolting for supports is also included with these components and inspected for loss of material and preload by inspecting for missing, detached, or loosened bolts and nuts in indoor air, outdoor air, and treated water environments. According to the applicant, the program relies on the design change procedures that are based on EPRI TR-104213 guidance to ensure proper specification of bolting material, lubricant, and installation torque. Identified degradation concerns are entered in the corrective action program for evaluation or correction to ensure the intended function of the affected component support is maintained. The applicant also stated that the program is implemented through corporate and station procedures, which provide inspection and acceptance criteria consistent with the requirements of ASME Section XI, Subsection IWF 2001 Edition through the 2003 Addenda as approved in 10 CFR 50.55a. The applicant further stated that the ISI program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified 12 months before the start of the inspection interval in accordance with 10 CFR 50.55a(g)(4)(ii).

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S3. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.S3, with the exception of the "scope of the program" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

GALL AMP XI.M18, "Bolting Integrity," states that GALL AMP XI.S3, "ASME Section XI, Subsection IWF," manages inspection of safety-related bolting. However, the applicant stated that its Bolting Integrity Program follows information that is delineated in NUREG-1339, published in EPRI NP-5769 guidelines, and recommended by industry. Although recommended inspections for SCC to prevent or mitigate degradation and failure of structural bolts with actual yield strength of 150,000 pounds per square inch (psi) are provided in EPRI NP-5769, EPRI TR-104213, and NUREG-1339, the applicant stated in LRA Section 3.5.2 that American Society for Testing and Materials (ASTM) A490 bolts have high resistance to SCC due to their ductility, and industry and plant-specific operating experience has not identified SCC of ASTM A490 bolts as a concern. To understand the basis for the applicant's statement, the staff needed additional information from the applicant to verify that its ASME Section XI, Subsection IWF Program is consistent with GALL AMP XI.S3. By letter dated May 14, 2010 (ADAMS Accession No. ML101060155), the staff issued RAI B.2.1.29-01 requesting that the applicant explain the basis for the conclusion that ASTM A490 bolts have resistance to SCC due to their ductility because published data indicate that ASTM A490 bolts have high hardness and are not ductile.

In its response dated June 14, 2010, the applicant stated that three parameters must exist for SCC to occur in high-strength bolting. These parameters include: (1) a corrosive environment,

(2) a susceptible material, and (3) high-sustained tensile stresses. The absence of any one of these three parameters eliminates the material's susceptibility to SCC. The applicant further stated that high-strength A490 bolting material used in nuclear steam supply system (NSSS) Class 1 component supports (RPV support) at HCGS is exposed to a normally noncorrosive indoor-air environment in containment and that lubricants containing molybdenum disulfide or unacceptable levels of contaminants are not approved for use on these bolts. Additionally, the bolts are not subject to high-sustained preload stress. Therefore, the applicant concluded that SCC is not considered an applicable aging mechanism requiring management. To further support this conclusion, the applicant also stated that "a review of industry documents, industry and site specific operating experience, and the fact that not all three parameters required for SCC are present, cracking due to SCC of ASTM A490 bolts was determined not to be an aging effect requiring management at Hope Creek Generating Station during the period of extended operation."

The staff finds this program acceptable because the applicant does not subject high-strength ASTM A490 bolts to unacceptable levels of contaminants or corrosive environments that can cause SCC. In addition, according to LRA Section B.2.1.12, A490 bolts used for NSSS Class 1 RPV supports were installed with a preload of 105,000 psi, which is less than the minimum yield strength of 130,000 psi of these bolts. The staff's concern described in RAI B.2.1.29-01 is resolved.

Based on its audit and review of the applicant's response to RAI B.2.1.29-01, the staff finds that elements one through six of the applicant's ASME Section XI, Subsection IWF Program are consistent with the corresponding program elements of GALL AMP XI.S3 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.29 summarizes operating experience related to the ASME Section XI, Subsection IWF Program. The first example of operating experience described by the applicant in LRA Section B.2.1.29 occurred during ASME Code Section XI, Subsection IWE inspections. In 2003, the applicant indicated that the ASME Section XI, Subsection IWE inspections identified light to heavy rust on nuts and washers for two bolts installed on a torus horizontal restraint (MC support). These bolts, nuts, and washers are components of the torus horizontal restraint which is managed by the ASME Section XI, Subsection IWF Program. Although the applicant noted that there was no measurable loss of material, the condition was entered in the corrective action program for evaluation. As a result, the remaining torus lateral restraint bolts, nuts, and washers were inspected during the next refueling outage (RF12). During this inspection, light to heavy rust was found on additional washers and nuts. Corrective actions were initiated to remove the rust from the washers and nuts. After the rust was removed, the supports were inspected, evaluated, and found acceptable for continued service without repair or replacement.

As another example of operating experience, the applicant stated that in 2006, eight ASME Classes 1, 2, 3, and MC component supports were subjected to VT-3 in accordance with ASME Section XI, Subsection IWF. The supports were inspected for degradation including corrosion, distortion, spring can functionality and settings, loose bolts and nuts, debris, and foreign material. The applicant reports that VT-3 qualified examiners observed no unacceptable indications. Also in 2006, the applicant identified one broken concrete anchor on the support for the 1-inch diameter service water pump lube water line and replaced the anchor in accordance with the HCGS Repair, Replacement Program. The replaced anchor was found broken during a service water intake structure walkdown. The applicant reported that corrosion due to service water leakage or spray was suspected as the failure mechanism for the anchor. An engineering evaluation concluded that the support was capable of performing its intended function with consideration for the remaining concrete anchors, but recommended the repair to restore the support to its design configuration. As a part of the extent of condition determination, similar supports at the service water intake structure were inspected. The inspections identified no additional broken concrete anchors.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.29 provides the UFSAR supplement for the ASME Section XI, Subsection IWF Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2. The staff also notes that the applicant committed (Commitment No. 29) to ongoing implementation of the existing ASME Section XI, Subsection IWF Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's ASME Section XI, Subsection IWF Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.16 10 CFR Part 50, Appendix J

Summary of Technical Information in the Application. LRA Section B.2.1.30 describes the existing 10 CFR 50, Appendix J Program as consistent with GALL AMP XI.S4, "10 CFR Part 50, Appendix J." The LRA further states that the program assures leakage through the primary containment and systems and components penetrating primary containment do not exceed allowable leakage rate limits in the TSs. The LRA further states that the program does not prevent degradation but provides measures for monitoring to detect degradation prior to the loss of intended function. HCGS is implementing Option B of the program, which allows the testing intervals to be performance based.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S4. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.S4. Based on its audit, the staff finds that elements one through six of the applicant's 10 CFR 50, Appendix J Program are consistent with the corresponding program elements of GALL AMP XI.S4 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.30 summarizes operating experience related to the 10 CFR 50, Appendix J Program. The applicant stated that the cumulative maximum leakage test results at HCGS in 2007 were approximately 40 percent of the total allowable limit specified in the TSs. The applicant further stated that a focused area self-assessment conducted for the 10 CFR 50, Appendix J Program was completed in 2007 and the overall rating of the program was satisfactory. The applicant also provided documented notices of local leak-rate test (LLRT) failures where the initial LLRT exceeded the inservice testing (IST) limit. For these cases, the 10 CFR 50, Appendix J program engineer determined that the leakage above the IST limit would not have a significant safety impact on HCGS or result in an increased radiological dose to the test performers. Therefore, the applicant determined that the current leakage is acceptable until the LLRT performance in the next refueling outage.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.30 provides the UFSAR supplement for the 10 CFR 50, Appendix J Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2. The staff also notes that the applicant committed (Commitment No. 30) to ongoing implementation of the existing 10 CFR 50, Appendix J Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's 10 CFR 50, Appendix J Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.17 Protective Coating Monitoring and Maintenance

Summary of Technical Information in the Application. LRA Section B.2.1.34 describes the existing Protective Coating Monitoring and Maintenance Program as consistent with GALL AMP XI.S8, "Protective Coating Monitoring and Maintenance Program." The applicant stated that the Protective Coating Monitoring and Maintenance Program is an existing program that manages cracking, blistering, flaking, peeling, and delamination of Service Level 1 coatings subjected to indoor air in the containment structure. The applicant's Protective Coating Monitoring and Maintenance Program defines a Service Level 1 coating as a coating system used in areas in reactor containment where the coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown, which is consistent with RG 1.54, Revision 1.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S8. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.S8. Based on its audit, the staff finds that elements one through six of the applicant's Protective Coating Monitoring and Maintenance Program are consistent with the corresponding program elements of GALL AMP XI.S8 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.34 summarizes operating experience related to the Protective Coating Monitoring and Maintenance Program. The applicant provided the following examples of operating experience as objective evidence that the Protective Coating Monitoring and Maintenance Program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

(1) In 2001, an inspection of the HCGS Service Level 1 coatings was performed during the refueling outage. The inspection methodology was based on the guidelines of ASTM D 5163. The inspections covered five areas: (1) primary containment outside of the torus, (2) drywell at elevations - feet and 109 through 127 feet, (3) drywell head and flange, (4) interior of the torus, and (5) drywell at elevation 87 feet. The inspection consisted of visual examinations, including references to industry pictorial standards, on the various metal and concrete surfaces in the selected areas. The summary of inspections in the coatings report indicated that the coatings applied to metal and concrete surfaces were in good condition. Recommendations were made for future maintenance work in the drywell and torus and documented in the corrective action

program. This example provides objective evidence that the Protective Coating Monitoring and Maintenance Program is effective in monitoring, trending, and assessing the condition of the Service Level 1 coatings and documenting coating conditions.

(2) In 2004, a diver inspection was performed in the torus during the refueling outage. The purpose of the inspection was to assess the conditions of the underwater torus coatings and underlying metallic surfaces of the torus. The inspectors found 39 areas with coating deficiencies, all of which were due to mechanical damage as opposed to other forms of disbondment such as cracking, peeling, and delamination. The loss of material due to corrosion of the underlying steel (maximum loss was measured at 28 mils) at the areas of the 39 identified coating deficiencies was within the acceptance criteria of 94 mils. Although the mechanism of the coating deficiencies were not related to the coatings' ability to adhere to the substrate and that the observed loss of material on the torus metal surfaces were within the acceptance criteria, coating repairs were performed during the 2004 refueling outage. This example provides objective evidence that the Protective Coating Monitoring and Maintenance Program is effective in assessing and correcting the conditions of the Service Level 1 coatings underwater in the torus.

(3) During the 2009 refueling outage, the HCGS Service Level 1 coatings in the drywell were inspected following the guidelines of ASTM D 5163. Due to limited access, the coatings assessment was limited to coatings applied to steel and concrete surfaces at elevations 102 feet and 87 feet. The first area assessed was the concrete floor to drywell shell interface at elevation 87 feet to determine the condition of the coatings. The coatings did not exhibit any signs of peeling or delamination. There was no visible corrosion on the drywell shell. The remaining coating inspections consisted of visual examinations on the various metal and concrete coated surfaces. The summary of inspections in the coatings report indicated that the coatings applied to metal and concrete surfaces were in good condition. There were many instances of small areas of mechanically-damaged coatings bounded by sound coatings. These conditions were documented in the corrective action program and were satisfactorily addressed in the 2009 refueling outage. This example provides objective evidence that the Protective Coating Monitoring and Maintenance Program is effective in assessing and correcting the conditions of the Service Level 1 coatings.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation. Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.34 provides the UFSAR supplement for the Protective Coating Monitoring and Maintenance Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2. The staff also notes that the applicant committed (Commitment No. 34) to ongoing implementation of the existing Protective Coating Monitoring and Maintenance Program for managing aging of applicable components during the period of extended operation.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Protective Coating Monitoring and Maintenance Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.18 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B.2.1.35 describes the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as consistent with GALL AMP XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The applicant stated that the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program manages embrittlement, cracking, swelling, surface contamination, or discoloration to ensure that electrical cables, connections, and terminal blocks not subject to the EQ requirements of 10 CFR 50.49 but are within the scope of license renewal and are capable of performing their intended functions.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.E1. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.E1. Based on its audit, the staff finds that elements one through six of the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program are consistent with the corresponding program elements of GALL AMP XI.E1 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.35 summarizes operating experience related to the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The applicant stated that in April 17, 2006, a motor lead damaged by heat exposure was visually discovered at HCGS. An engineering evaluation of the cable condition was performed. The damaged portion of the cable was removed and new cable was spliced into place to eliminate the heat-damaged cable completely. The applicant also stated that in March 2, 2004, a power cord in the radiation monitoring system was visually discovered, by an engineer during a periodic system walkdown, to have a degraded outer insulation (jacket). The power cable was replaced prior to any loss of function in accordance with the corrective action program.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.35 provides the UFSAR supplement for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualifications Requirements Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.6-2. The staff also notes that the applicant committed (Commitment No. 35) to implement the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.19 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

Summary of Technical Information in the Application. LRA Section B.2.1.36 describes the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program as consistent with GALL AMP XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits." The applicant stated that the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program manages the in-scope portions of the radiation monitoring system, and the neutron monitoring system not included in the EQ program. This program applies to sensitive instrumentation cable and connection circuits with low-level signals that are within the scope of license renewal and are located in areas where the cables and connections could be exposed to adverse localized environments caused by heat, radiation, or moisture.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.E2. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.E2. Based on its audit, the staff finds that elements one through six of the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program are consistent with the corresponding program elements of GALL AMP XI.E2 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.36 summarizes operating experience related to the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program. The applicant stated that, in November 2004, a common cause analysis was initiated in response to an adverse trend with problems with instrumentation cables located under the reactor vessel. The applicant found water collecting on the top of the sleeve, which eventually caused leaking of water into the connector. The problem was resolved by removing the sleeves to improve the cable water resistance. The applicant also stated that, in April 2002, a degraded sensor cable was discovered on the turbine building circulating water sump radiation monitor. A radiation monitor spiked, tripping the turbine building circulating water sump. The cable was later replaced and the detector checked.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.36 provides the UFSAR supplement for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.6-2. The staff also notes that the applicant committed (Commitment No. 36) to implement the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.20 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B.2.1.37 as supplemented by letter dated September 7, 2010, and September 30, 2010, describes the new Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as consistent with GALL AMP XI.E3, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The applicant stated that its program manages inaccessible power cables (480 volts (V), 4,160V, and 13,800V) that are exposed to significant moisture simultaneously with significant voltage. The applicant stated that significant moisture is defined as periodic exposure to moisture that lasts more than a few days (e.g., cable in standing water). The applicant also stated that significant voltage exposure is defined as being subject to system voltage for more than 25 percent of the time. The applicant noted that no inaccessible power cable exposed to significant moisture was excluded from the program due to the "significant voltage" criterion. The applicant further stated that in-scope, non-EQ, inaccessible power cables subject to significant moisture and voltage will be tested as part of this AMP. The applicant stated that these power cables will be tested using a proven test for detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, or polarization index as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed. Finally, the applicant stated that the cable test frequency will be established based on test results and industry operating experience. The maximum time between tests will be no longer than 6 years. The applicant further stated that the first tests will be completed prior to the period of extended operation.

The applicant stated that prior to the period of extended operation, manholes and cable vaults, associated with cables included in this AMP, will be inspected for water collection with water removal done as necessary. In-scope, non-EQ, inaccessible power cables subject to significant moisture and voltage will be evaluated, so that draining or other corrective actions can be taken. The applicant also stated that the objective of the inspections, as a preventive action, is to minimize the exposure of power cables to significant moisture. The frequency of inspections for accumulated water will be established based on inspection results. The applicant further stated that this approach to determining the inspection frequency recognizes a recurring inspection, set at the optimum frequency, would result in the cables being submerged only as a result of event driven, rain and drain, type occurrences and that station procedures will direct the assessment of the cable condition as a result of rain or other event driven occurrences. The applicant stated that sufficient manhole and cable vault inspections will be performed prior to the period of extended operation so that proper inspection frequencies are established to minimize the exposure of power cables to significant moisture during the period of extended operation. Finally, the applicant stated that the maximum time between inspections will be no more than 1 year.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.E3. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.E3. Based on its audit, the staff finds that elements one through six of the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program are consistent with the corresponding program elements of GALL AMP XI.E3 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.37 summarizes operating experience related to the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The applicant stated that, in response to GL 2007-01, "Inaccessible or Underground Power Cable Failures That Disable Accident Mitigation Systems or Cause Plant Transients," the plant has no history of failures of inaccessible or underground medium or low (480V or greater) voltage power cables.

The LRA provided examples of operating experience that the applicant stated provided objective evidence that the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will be effective in assuring that intended functions will be maintained consistent with the CLB for the period of extended operation. Examples include:

(1) References to testing of a representative sample of medium voltage cables as part of existing maintenance procedures for megger testing rotating electrical equipment and associated power cables.

(2) Reference to August 2007 standing water and potential flooding of cable vaults containing motor feed and control cable for service water. Corrective action consisted of re-grading the yard area to minimize rainwater from pooling on the vaults and conducting inspections of two cable vaults and pumping water from these vaults due to cable submergence identified in the vaults. The cable vault structure was found to be in good material condition.

(3) The applicant's February 2008 self-assessment of critical medium voltage underground cable and the applicant's follow-up actions to develop a test program and institute preventive maintenance activities.

Based on these examples, the applicant stated that detection methods exist to identify aging effects and prevent the loss of intended function, corrective actions have accounted for industry operating experience, and industry operating experience will be used to improve the program such that, if any aging effects do occur, they would be detected prior to loss of intended function.

The staff reviewed the operating experience in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the applicant's plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. Furthermore, the staff performed a search of regulatory operating experience for the period 2000 through November 2009. Databases were searched using various keywords and then reviewed by the technical auditor staff.

During its review, the staff identified operating experience which needed additional clarification to determine if the applicant's program will be effective in adequately managing aging effects during the period of extended operation. The staff's need for additional clarification resulted in the issuance of an RAI.

Prior to the license renewal AMP audit in June 2009, the applicant inspected manholes associated with medium voltage cables for the "C" service water pump. Each manhole includes separate vaults per train with a separate cover for each vault. There are a total of three manholes. Two manholes contain vaults for two service water trains (A and C) and (D and B), respectively. The third manhole contains four separate vaults, one for each service water train (A, B, C, and D). The applicant's inspection of the "C" vaults found standing water in both vaults with the "C" train service water medium voltage cables submerged. The applicant generated a condition report to address the standing water in the "C" service water vaults. The condition report also included the service water A, B, and D trains based on the expectation that scheduled follow-on inspections would also find submerged cables in these vaults. The applicant noted in the condition report that the duct banks containing the service water medium voltage cables are designed to drain water away from the service water building and reactor building into the manholes and vaults, but there is no drainage system to remove water from the vaults. The condition report noted that the vaults contain sumps, but that sump pumps were never installed.

The "A" vaults were inspected in September 2009 and also found to have standing water and submerged service water medium voltage cables. The staff was present during this inspection and observed the vaults once they were pumped out. The staff also noted that the service water medium voltage cables contained splices at both "A" vault locations. During this site visit, the staff also reviewed inspections findings and photographs of the previous "C" service water vault inspection. In November 2009, both the "B" and "D" vaults were inspected by the applicant with standing water and medium voltage cable submergence also noted for these vaults. The staff was present for the "D" vault inspections and also discussed cable test results and inspection results for the "B" vault. The staff again noted that the service water medium voltage cables contained splices at both "D" vault locations. The staff confirmed that service water medium voltage cable splices were also located in the "C" and "B" vault locations.

On September 30, 2009, the staff issued an integrated inspection report (Report #05000354/2009004) for HCGS and identified submerged medium voltage cable associated with "A" and "C" service water medium voltage cable inspections. The inspection report notes that the inspectors verified that the applicant conducted an adequate operability evaluation associated with the cables and identified appropriate corrective action. The report also states that the inspectors verified the integrity of cables and splices and the condition of the cable support structure. The inspection report identified the “A” and “C” submerged service water medium voltage cables as a non-cited violation of very low safety significance (green) since it did not represent an actual loss of safety function or contribute to external event core damage sequences.

During the audit, the staff also interviewed HCGS personnel and reviewed documentation for in-scope medium voltage inaccessible cables associated with station blackout (SBO) to determine whether these cables were also subject to submergence. The applicant stated that the manholes and one cable pit associated with SBO were inspected in July 2009, and cable submergence was noted during these inspections. The staff was concerned that the applicant’s Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program may not be adequate based on current operating experience with submerged cables.

By letter dated May 14, 2010, the staff issued RAIs B.2.1.37-1 and B.2.1.37-2 requesting that the applicant explain how LRA Section B.2.1.37 meets GALL AMP XI.E3 for in-scope, inaccessible medium voltage cables (including SBO recovery cables) based on plant operating experience that shows in-scope inaccessible medium voltage cables exposed to significant moisture (more than a few days).

Regarding plant-specific operating experience with submerged service water cables, the staff requested in RAI B.2.1.37-1 that the applicant:

> Describe how HCGS LRA AMP B.2.1.37 meets GALL AMP XI.E3 considering that operating history shows that the in-scope inaccessible medium voltage cable are exposed to significant moisture (i.e., exposure lasting more than a few days). In addition, (a) describe how plant operating experience were incorporated into AMP B.2.1.37 to minimize exposure of in-scope inaccessible medium voltage cables to significant moisture during the period of extended operation, (b) discuss manhole and vault inspections (including event-driven significant moisture exposure such as rain) and how adjustments and modifications will be made based on operating experience to minimize cable exposure to significant moisture, (c) discuss any corrective actions taken that address submerged cable conditions and cable support structure degradation identified through manhole and vault inspection, and (d) discuss cable testing frequency and applicability that demonstrates in-scope, inaccessible medium voltage cables will continue to perform their intended function during the period of extended operation.

The applicant responded by letters dated June 14, 2010, and August 9, 2010, and stated:

> The Hope Creek LRA AMP B.2.1.37, Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, is a new program that is currently in the process of being implemented at Hope Creek. This program includes (1) testing of in-scope, inaccessible medium voltage cables subject to significant moisture and significant voltage and (2) inspection of cable vaults, including subsequent pumping of accumulated water if required, as a preventive measure to minimize the potential exposure of in-scope cables to significant moisture.
>
> Specifically, each of the in-scope service water cables was tested between September and November 2009. The cable test results determined that all of the in-scope service water cable insulations are in good condition. In-scope service

> water cable testing will continue to be conducted periodically [every 18 months] during their associated service water pump motor outages. The cable test frequency may be adjusted based on data trending in accordance with the corrective action process.
>
> Plant-specific operating experience has identified cable vault water accumulation resulting in exposure of the in-scope service water cable to significant moisture. This condition was reported and evaluated in the corrective action process. Based on this identified operating experience and in accordance with the corrective action process, Hope Creek has commenced periodic inspections of the in-scope service water cables, and removing accumulated water as required, to monitor the in-scope service water cables. The service water cable vaults are currently inspected for water accumulation weekly. Trending and characterization of the water intrusion rate allow adjustments to the service water cable vault inspection frequency in accordance with the corrective action process.

The applicant also stated that the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program implementation plan includes, prior to the period of extended operation, additional service water cable vault inspections will be performed and the frequency of inspections for accumulated water will be adjusted based on inspection results to ensure that the in-scope service water cables are not exposed to significant moisture. The maximum time between inspections will be no longer than 2 years, which meets the recommended frequency in GALL AMP XI.E3.

The applicant also stated that the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements meets GALL AMP XI.E3 for the in-scope service water cable because initial tests have been implemented and will be periodically performed (not to exceed 10 years) and, prior to the period of extended operation, the frequency of inspections for accumulated water will be established (not to exceed 2 years) based on inspection results to ensure that in-scope service water cables are not exposed to significant moisture during the period of extended operation.

The applicant further stated that physical modifications have been made to the service water cable vault lids to allow more frequent inspections and water pumping. The applicant also stated that the cable vault lid feature also accommodates future adjustments in inspection frequency including assessing the cable condition as a result of rain or other event-driven occurrences as directed by station procedures (e.g., hurricane, tropical storm, or coastal flooding warnings issued for the site area prompts the inspection and assessment of the cable vaults for water accumulation).

The applicant did not identify concrete-related issues or conditions adverse to quality for the service water cable vault structures. During the service cable vault inspection, the applicant noted that most cable supports experienced failure of the galvanized surface coating, but no degradation of the structural integrity of the steel structure was observed. The applicant stated that corrective actions have been initiated to repair the galvanized steel coating on the cable supports.

Regarding plant-specific operating experience with submerged SBO cables, the staff requested in RAI B.2.1.37-2 that the applicant:

> Describe how HCGS LRA AMP B.2.1.37 meets GALL AMP XI.E3 for in-scope inaccessible medium voltage SBO recovery cables considering that operating history shows that the in-scope inaccessible medium voltage SBO recovery cables are exposed to significant moisture (i.e., exposure lasting more than a few days). In addition, (a) describe how plant operating experience were incorporated into AMP B.2.1.37 to minimize exposure of SBO in-scope inaccessible medium voltage cables to significant moisture during the period of extended operation, (b) discuss any corrective actions taken that addresses submerged cable conditions and cable support structure degradation identified through manhole/vault inspections, and (c) discuss cable testing frequency and applicability that demonstrates in-scope, inaccessible medium voltage cable will continue to perform their intended function during the period of extended operation

The applicant responded by letters dated June 14, 2010, and August 9, 2010, and stated:

> The Hope Creek LRA AMP B.2.1.37, Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, is a new program that is currently in the process of being implemented a Hope Creek. This program includes (1) testing of in-scope, inaccessible medium voltage cables subject to significant moisture and significant voltage and (2) inspection of cable manholes, including subsequent pumping of accumulated water if required, as a preventive measure to minimize the potential exposure of in-scope cables to significant moisture.
>
> Specifically, Hope Creek will perform cable testing of the in-scope SBO recovery cables during their associated transformer outages. The first test is scheduled for October 2010. The current plan is to test the in-scope SBO recovery cables periodically during their associated transformer outages. The cable test frequency may be adjusted based on data trending.
>
> Plant-specific operating experience has identified cable vault water accumulation resulting in exposure of the in-scope SBO recovery cables to significant moisture. This condition was reported and evaluated in the corrective action process. Based on this identified operating experience and in accordance with the corrective action process, Hope Creek has commenced periodic ([every] 18 months) inspections of the in-scope SBO recovery cable manholes/pits and removing accumulated water as required to monitor the in-scope SBO recovery cables.
>
> Prior to the period of extended operation, additional SBO recovery cable manhole inspections will be performed and the frequency of inspections for accumulated water will be adjusted based on inspection results to ensure that the in-scope SBO recovery cables are not exposed to significant moisture. The maximum time between inspections will be no longer than 2 years, which meets the recommended frequency in GALL AMP XI.E3.
>
> The Hope Creek LRA AMP B.2.1.37 meets GALL AMP XI.E3 for the in-scope SBO recovery cables because prior to the period of extended operation, cable

> tests will be periodically performed (not to exceed 10 years) and, prior to the period of extended operation, the frequency of inspections for accumulated water will be established (not to exceed 2 years) based on inspection results to ensure that the in-scope SBO recovery cables are not exposed to significant moisture during the period of extended operation.

In its RAI response, the applicant identified 5 manholes and 2 cable pits that are in-scope for SBO inaccessible medium voltage cables. The applicant stated that 3 manholes and 1 cable pit were inspected between April and June 2009. The applicant noted that 2 of the 3 manhole inspections and the cable pit inspection identified submerged cables. The applicant stated that the manholes were subsequently dewatered. The applicant also stated that no cable defects, concrete, cable support related issues or conditions adverse to quality were observed for all cables within these 3 manholes and 1 cable pit. The applicant did note that the cable pit showed evidence of a conduit failure. The condition was entered into the corrective action process with repairs scheduled for April 2012. The applicant further stated that the remaining 2 manholes are planned to be inspected during the next respective transformer outages in April 2012 (station service transformers). The applicant plans to inspect the remaining cable pit in October 2010. By letter dated January 19, 2011, the applicant provided updated information concerning SBO cable testing performed during the October 2010 refueling outage. The applicant stated that testing of the “B” channel of the in-scope SBO 13-kilovolt (kV) cables was conducted and the test results were acceptable. The applicant also stated that testing of the “A” channel is scheduled for 2012 with follow-up testing of the “B” channel scheduled for 2013.

The applicant stated that as a result of this operating experience, actions have been initiated to establish recurring tasks to open, inspect, and dewater manholes and cable pits. The applicant noted that cable condition is also assessed as a result of rain or other event-driven occurrences as directed by station procedures. The applicant further stated that trending and characterizing the water intrusion rate allow adjustments to the SBO recovery cable manhole inspection frequency in accordance with the corrective action process.

The applicant stated that it is planning to perform SBO recovery cable testing every 3 years during station service transformer outages. The applicant also stated that testing will be conducted periodically in order to trend and characterize the SBO recovery cable insulation condition. As noted above, by letter dated January 19, 2011, the applicant provided updated information concerning SBO cable testing that was performed during the October 2010 refueling outage.

The staff has concluded, based on recently identified industry operating experience concerning the failure of inaccessible low voltage power cables (480V to 2kV) in the presence of significant moisture, that these cables can potentially experience aging effect related degradation.

The staff was also concerned that recent industry operating experience also showed an increasing trend in cable failures with a length of service beginning in the 6th through 10th year of operation. The staff determined, based on the review of the cable failure distribution, that annual inspection of cable manholes and a cable testing frequency of at least every 6 years is a conservative approach to ensuring the operability of inaccessible power cables and, therefore, should be considered. The staff noted that the applicant’s Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program did not address inaccessible low voltage power cables.

By teleconference dated August 16, 2010, the staff discussed with the applicant the cable test and manhole/vault inspection frequencies and the inclusion of inaccessible low voltage cables into the scope of the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program based on recent industry operating experience. By letter dated September 7, 2010, the applicant submitted a supplement to the LRA to include inaccessible low voltage power cables in the scope of the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The applicant stated the following:

> The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is changed to include low voltage power cables (480V or greater) that are exposed to significant moisture. In addition, the criterion for significant voltage has been clarified because all inaccessible power cables (480V, 4,160V, and 13,800V) exposed to significant moisture at Hope Creek are included in this program. No inaccessible power cable exposed to significant moisture is excluded from the program due to the "significant voltage" criterion. Finally, operating experience has been updated to include the fact that there have been no underground or inaccessible low voltage cable failures at Hope Creek.

The applicant revised LRA Appendix A, Section A.2.1.37, Section A.5, License Renewal Commitment List, Commitment No. 37, and LRA Appendix B, Section B.2.1.37 to revise the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program to include inaccessible low voltage power cables (480V to 2kV). The applicant also updated operating experience to include in-scope inaccessible low voltage power cables stating that HCGS has no history of failures for these cables. The applicant also revised the LRA to state that no inaccessible power cable was excluded from the AMP due to "significant voltage" criterion.

However, in its September 7, 2010, LRA supplement, the applicant did not address the effect of industry and plant-specific operating experience concerning inaccessible power cable tests or cable manhole and vault inspection frequencies referenced by GALL Report AMP XI.E3 (10 and 2 years respectively). By teleconference dated September 9, 2010, the staff asked the applicant to explain why an increased cable test and cable manhole and vault inspection frequency for in-scope inaccessible power cables based on recent industry and plant-specific operating experience is not appropriate for HCGS. During the conference call, the applicant agreed to evaluate increased test and inspection frequencies for HCGS. By letter dated September 30, 2010, the applicant supplemented its LRA to change the maximum cable test frequency from 10 years to 6 years and the maximum cable vault and manhole inspection frequency from 2 years to 1 year. With the change to the applicant's cable vault and manhole inspection frequencies and cable test frequencies, confirmatory item CI 3.0.3.1.20-1 is closed.

Based on the applicant's responses to RAIs B.2.1.37-1 and B.2.1.37-2, and information provided in the applicant's LRA supplement dated September 7, 2010, and September 30, 2010, the staff finds that:

(a) The applicant has appropriately expanded the program scope to include inaccessible low voltage power cables (480V to 2kV) and clarified that no inaccessible power cable was excluded based on the "significant voltage" criterion. The applicant noted that the increased scope to include inaccessible low voltage power cable did not result in additional cable vaults being added to the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

(b) HCGS cable insulation testing is appropriate because: (1) it considers plant-specific and industry operating experience, (2) plant-specific operating experience has not revealed any instance of inaccessible power cable failure due to aging related effects within the scope of the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, and (3) the actual frequency of testing may be adjusted based on test results and operating experience and is currently scheduled every 18 months for in-scope inaccessible service water power cables and every 3 years for in-scope SBO inaccessible power cables. This approach is consistent with the discussion of operating experience in the SRP-LR Section A.1.2.3.10, which states that applicants should consider plant-specific and applicable industry operating experience for its AMPs.

(c) The applicant's inspection frequency for cable vaults and manholes and cable pits containing inaccessible in-scope power cables is appropriate because it takes into account applicable industry and plant-specific operating experience including cable vault and manhole and cable pit water accumulation at HCGS. The actual periodic frequency of inspection will be established prior to the period of extended operation based on inspection results and is currently weekly for in-scope service water vaults and every 18 months for in-scope SBO manholes and cable pits. The SBO cables are normally energized, therefore, maintenance and inspection activities are typically scheduled during refueling outages. Additional inspections are performed based on event-driven occurrences such as rain or other event-driven occurrences as directed by station procedures. Given that plant-specific operating experience has shown significant water accumulation in cable vaults and manholes and cable pits within the scope of this AMP, an inspection frequency determined through inspection results and additional inspections based on event-driven occurrences is acceptable because the applicant's current trending effort will continue to inform the program's inspection periodicity (i.e., to provide feedback for changes of the inspection periodicity as appropriate).

(d) The applicant also addressed the effect of industry and plant-specific operating experience concerning inaccessible power cable test and cable manhole and vault inspection frequencies by changing the maximum cable test frequency from 10 years to 6 years and the maximum cable vault and manhole inspection frequency from 2 years to 1 year.

The staff finds that with the enhancements described above, the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will adequately manage the aging effects of inaccessible power cables, consistent with industry operating experience, such that there is reasonable assurance that inaccessible power cables (480V and greater) subject to significant moisture will be adequately managed during the period of extended operation. The staff's concern with respect to the inclusion of inaccessible low voltage power cables is resolved. With the resolution of confirmatory item CI 3.0.3.1.20-1, the staff's concern with test and inspection frequencies is resolved.

Based on its audit, review of the applicant's application, review of the applicant's responses to RAIs B.2.1.37-1 and B.2.1.37-2, and the LRA supplements dated September 7, 2010, and September 30, 2010, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program.

The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.37 provides the UFSAR supplement for the Inaccessible Medium Voltage Cables not subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.6-2.

By letter dated May 14, 2009, the staff issued RAI B.2.1.37-4 to request that the applicant discuss why the LRA Appendix A, Section A.2.1.37, UFSAR summary description does not include definitions of significant moisture and significant voltage consistent with SRP-LR Table 3.6-2 and LRA Section B.2.1.37. The applicant responded by letter dated June 14, 2010, and stated that LRA Section A.2.1.37 is revised to include these definitions. With the information provided by the applicant's RAI response, the staff finds the UFSAR supplement acceptable because the applicant revised LRA Section A.2.1.37 to be consistent with the guidance of SRP-LR Table 3.6-2. Based on the applicant's response to RAI B.2.1.37-4, the staff's concern described in RAI B.2.1.37-4 is resolved. In addition, as part of the applicant's supplement to the LRA dated September 7, 2010, the applicant revised LRA Section A.2.1.37 to include low voltage power cables (480V or greater) to the scope of the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, clarifying that no inaccessible power cables were excluded from the program due to the "significant voltage" criterion, and added condition-based inspections for manhole and cable vaults. Finally, as part of the applicant's supplement to the LRA dated September 30, 2010, the applicant resolved confirmatory item CI 3.0.3.1.20-1 by addressing the effect of industry and plant-specific operating experience concerning inaccessible power cable test and cable manhole and vault inspection frequencies by changing the maximum cable test frequency from 10 years to 6 years and the maximum cable vault and manhole inspection frequency from 2 years to 1 year. With the resolution of confirmatory item CI 3.0.3.1.20-1 concerning inspection and test frequencies, the staff determines that the applicant's UFSAR supplement provides an adequate summary description consistent with guidance of SRP-LR Table 3.6.

The staff also notes that the applicant committed (Commitment No. 37) to implement the new Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program prior to entering the period of extended operation for managing aging of applicable components. Specifically, Commitment No. 37 states:

> Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to manage the aging effects and mechanisms of non-EQ, in-scope inaccessible power cables (480V, 4,160V, 13,800V)
>
> The cable test frequency will be established based on test results and industry operating experience. The maximum time between tests will be no longer than 6 years.
>
> Manholes and cable vaults associated with the cables included in this aging management program will be inspected for water collection (with water removal as necessary) with the objective of minimizing the exposure of power cables to significant moisture. Prior to the period of extended operation, the frequency of inspections for accumulated water will be established based on inspection results to minimize the exposure of power cable to significant moisture. The maximum time between inspection will be no loger than one year.

The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be enhanced as follows:

1. Add low voltage power cables (480 volts or greater) to the scope of the program.

2. Change cable testing maximum frequency from 10 years to 6 years. Change cable vault and manhole inspection maximum frequency from 2 years to 1 year.

The staff determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the resolution of RAIs and confirmatory item CI 3.0.3.1.20-1, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.21 Metal Enclosed Bus

Summary of Technical Information in the Application. LRA Section B.2.1.38 describes the new Metal Enclosed Bus Program as consistent with GALL AMP XI.E4, "Metal Enclosed Bus." The applicant stated that the Metal Enclosed Bus Program manages the aging of in-scope metal enclosed buses within the scope of license renewal to ensure that they are capable of performing their intended functions. The applicant also stated that internal portions of the in-scope metal enclosed bus enclosures will be visually inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of moisture intrusion. Furthermore, loose-bolted connections will be checked by sampling using thermography from outside of the metal enclosed bus.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.E4. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.E4. Based on its audit, the staff finds that elements one through six of the applicant's Metal Enclosed Bus Program are consistent with the corresponding program elements of GALL AMP XI.E4 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.38 summarizes operating experience related to the Metal Enclosed Bus Program. The applicant stated that, in January 2006, an electrical transient occurred in the HCGS switchyard in an outdoor section of non-segregated metal enclosed bus associated with the 13.8-kV island substation. The electrical fault was due to a breakdown of insulation properties between bus bars caused by tracking across a dislodged insulating boot.

The cause of the dislodged insulating boot was improper installation of the bus bar protective boots. A lack of effective preventive maintenance also contributed to this electrical transient because the last corrective maintenance action occurred 10 years prior. Corrective actions included installing new boots with an approved design, establishing appropriate PM tasks for this metal enclosed bus section, and completing the extent of condition inspections of adjoining transformers' metal enclosed bus sections for similar conditions. The applicant also stated that, in March 2005, the applicant found deterioration of an alignment cover on the outdoor portions of metal enclosed bus during a visual inspection. The alignment cover is a protective covering over the links, comprised of a neoprene rubber material. A total of eight alignment joint assemblies were subsequently replaced or repaired. The bus enclosures were found to be clean, with no evidence of overheating of bus connections.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.38 provides the UFSAR supplement for the Metal Enclosed Bus Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.6-2. The staff also notes that the applicant committed (Commitment No. 38) to implement the new Metal Enclosed Bus Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review of the applicant's Metal Enclosed Bus Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.22 Environmental Qualification (EQ) of Electric Components

Summary of Technical Information in the Application. LRA Section B.3.1.2 describes the existing EQ of Electric Components Program as consistent with GALL AMP X.E1, "Environmental Qualification (EQ) of Electric Components Program." The applicant also stated that the EQ of Electric Components Program manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations in adverse localized environments. The applicant stated that program activities establish, demonstrate, and document the level of qualification, qualified configuration, maintenance, surveillance, and replacement requirements necessary to meet 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants." The applicant further stated that qualified life is determined for equipment within the scope of the EQ of Electric Components Program, and that appropriate actions, such as replacement, refurbishment, or reanalysis, are taken prior to or at the end of the qualified life of the equipment so that the aging limit is not exceeded. The applicant also stated that the program ensures maintenance of the qualified life for electrical equipment within the scope of the EQ of Electric Components Program through the period of extended operation.

As required by 10 CFR 50.49, EQ program components not qualified for the current license term are refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluations. Aging evaluations for EQ program components are TLAAs for license renewal.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP X.E1. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP X.E1. Based on its audit, the staff finds that elements one through six of the applicant's EQ of Electric Components Program, are consistent with the corresponding program elements of GALL AMP X.E1 and, therefore, acceptable.

Operating Experience. LRA Section B.3.1.2 summarizes operating experience related to the EQ of Electric Components Program. The applicant stated its program is an existing program, which implements preventive activities to ensure that the qualified life of components within the scope of the program is maintained through the period of extended operation. The applicant also stated that the effects of aging are effectively managed by objective evidence that demonstrates that aging effects and mechanisms are adequately managed.

The applicant's operating experience includes the use of actual area temperature data to assess the impact on the qualified life of the HPCI pump motor, indicating that the program is capable of addressing changing plant conditions and assessing the EQ impact on components. Additional examples include actions to improve scheduling of EQ work orders including improved accounting for procurement lead times and outages and a program to convert EQ files to electronic format that included a re-evaluation of maintenance frequencies and benchmarking of EQ program files. The applicant stated these examples demonstrate that its program addresses changing plant conditions, and identifies and incorporates corrective actions and EQ program improvement.

The staff reviewed the operating experience in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.3.1.2 provides the UFSAR supplement for the EQ of Electric Components Program.

The staff reviewed this UFSAR supplement description of the program and notes that, in conjunction with the TLAA UFSAR supplement A.4.4, it conforms to the recommended description for this type of program as described in SRP-LR Table 4.4-2.

The staff also notes that the applicant committed (Commitment No. 47) to ongoing implementation of the existing EQ of Electric Components Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's EQ of Electric Components Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 AMPs That Are Consistent with the GALL Report with Exceptions or Enhancements

In LRA Appendix B, the applicant identified the following AMPs that were, or will be, consistent with the GALL Report, with exceptions or enhancements:

- Water Chemistry
- BWR Stress Corrosion Cracking
- Flow-Accelerated Corrosion

- Bolting Integrity
- Closed-Cycle Cooling Water System
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Fire Protection
- Fire Water System
- Aboveground Steel Tanks
- Fuel Oil Chemistry
- Reactor Vessel Surveillance
- Buried Piping Inspection
- Lubricating Oil Analysis
- ASME Section XI, Subsection IWE
- Masonry Wall Program
- Structures Monitoring Program
- RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"
- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Metal Fatigue of Reactor Coolant Pressure Boundary

For AMPs that the applicant claimed are consistent with the GALL Report, with exceptions or enhancements, the staff performed an audit to confirm that those attributes or features of the program for which the applicant claimed consistency with the GALL Report were indeed consistent. The staff also reviewed the exceptions and enhancements to the GALL Report to determine whether they were acceptable and adequate. The results of the staff's audit and reviews are documented in the following sections.

3.0.3.2.1 Water Chemistry

Summary of Technical Information in the Application. LRA Section B.2.1.2 describes the existing Water Chemistry Program as consistent, with exceptions, with GALL AMP XI.M2, "Water Chemistry." The applicant stated that its program monitors and controls the chemical environments of those systems that are exposed to reactor water, steam, condensate and feedwater, CRD water, demineralized water storage tank water, condensate storage tank water, torus water, and spent fuel pool (SFP) water. The program manages the aging effects of cracking, loss of material, reduction of neutron-absorbing capacity, and reduction of heat transfer for components exposed to sodium pentaborate, steam, and reactor coolant environments. The applicant also stated that its Water Chemistry Program follows the guidelines in EPRI 1008192, BWRVIP-130, “BWR Vessel and Internals Project BWR Water Chemistry Guidelines EPRI TR-1008192” (2004), which is a later revision of BWRVIP-29 (1994) and is consistent with the GALL Report, which recommends following industry guidelines of BWRVIP-29 (EPRI TR-103515), or later revisions. The applicant further stated that it has chosen to use ECP, the measured molar ratio of hydrogen to oxygen, as its primary indicator of IGSCC mitigation.

Staff Evaluation. During its audit, the staff reviewed the applicant’s claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant’s program to the corresponding elements of GALL AMP XI.M2. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M2.

The staff also reviewed the portions of the “scope of the program,” “parameters monitored or inspected,” and “detection of aging effects” program elements associated with the exceptions to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff’s evaluation of these exceptions follows.

Exception 1. LRA Section B.2.1.2 states an exception to the “scope of the program” and “parameters monitored or inspected” program elements. The applicant stated that “NUREG-1801 [the GALL Report] indicates that hydrogen peroxide is monitored to mitigate degradation of structural materials. The Hope Creek program does not monitor for hydrogen peroxide.”

As part of the audit, the staff interviewed the applicant’s technical personnel to discuss this exception and reviewed BWRVIP-130 and BWRVIP-190, “BWR Vessel and Internals Project BWR Water Chemistry Guidelines EPRI TR-1016579” (2008). During the interview, the applicant stated that it uses hydrogen addition and noble metal chemical applications to mitigate the occurrence of IGSCC by maintaining an ECP value less than -230 mV (millivolt), standard hydrogen electrode (SHE). The applicant also stated that it continuously monitors ECP in the reactor water system, and that by maintaining ECP less than -230 mV, SHE (below the action level value) the formation of hydrogen peroxide is sufficiently suppressed to mitigate the occurrences of IGSCC.

The staff notes that BWRVIP-190 provides sufficient guidance for using ECP to determine hydrogen-to-oxygen molar ratios in reactor water in order to minimize the formation of hydrogen peroxide and mitigate IGSCC. The staff also notes that the applicant’s Water Chemistry Program includes activities to ensure that the reactor water contains an adequate excess of hydrogen-to-oxygen such that the ECP is maintained below values necessary to mitigate the aging effects of hydrogen peroxide and IGSCC. The staff finds the applicant’s exception acceptable because using ECP as the principle indicator of IGSCC mitigation is consistent with BWRVIP-190 guidance and, therefore, is consistent with the GALL Report, which recommends following the guidance of BWRVIP-29 or later revisions.

Exception 2. LRA Section B.2.1.2 states an exception to the “scope of the program” and “parameters monitored or inspected” program elements. The applicant stated that “NUREG-1801 [the GALL Report] indicates that dissolved oxygen is monitored. The condensate storage tank water, demineralized water storage tank water, SFP water, and torus water are not sampled for dissolved oxygen."

As part of the audit, the staff interviewed the applicant's technical personnel to discuss this exception and reviewed BWRVIP-130 and BWRVIP-190. The applicant indicated it was consistent with industry guidelines, as recommended by the GALL Report, by following the industry guidelines of BWRVIP-130 and BWRVIP-190 (both are later revisions to BWRVIP-29). The applicant stated that the Water Chemistry Program required monitoring of conductivity, chlorides, sulfates, and total organic carbon (TOC) in accordance with BWRVIP-190, as its method for ensuring component integrity.

The staff notes that dissolved oxygen is not one of the diagnostic parameters recommended by the EPRI guidance documents for monitoring the health of the auxiliary systems, whereas conductivity, chlorides, sulfates, and TOC are all diagnostic parameters for the auxiliary systems recommended by the EPRI. The staff also notes that BWRVIP-190 is a later revision of BWRVIP-29 and that following the guidance of BWRVIP-190 is consistent with the GALL Report, which recommends following the guidance of BWRVIP-29 or later revisions. The staff finds the exception acceptable because it is consistent with the recommendations in BWRVIP-190, and the program monitors other water chemistry parameters that are acceptable to mitigate aging in the auxiliary systems.

Exception 3. LRA Section B.2.1.2 states an exception to the "scope of the program" and "parameters monitored or inspected" program elements. The applicant stated that "NUREG-1801 [the GALL Report] indicates that water quality (pH and conductivity) is maintained in accordance with established guidance. The pH is not monitored for torus water."

As part of the audit, the staff interviewed the applicant's technical personnel to discuss this issue and reviewed guidance provided in BWRVIP-190 and BWRVIP-130. The applicant stated in its exception that BWRVIP-130, "BWR Water Chemistry Guidelines," Section 8.2.1.11, indicates that pH measurement accuracy is unreliable in BWR streams because of the ionic strength of the samples. The applicant also stated that its Water Chemistry Program relies on monitoring conductivity, chlorides, and sulfates consistent with BWRVIP-190.

The staff reviewed the Water Chemistry Program and finds the exception acceptable because: (1) it is consistent with the guidance provided in BWRVIP-190 because pH is not a diagnostic parameter for torus water recommended by the EPRI, whereas conductivity, chloride, and sulfate are all recommended by the EPRI as diagnostic parameters for torus water; and (2) BWRVIP-190 is a later revision of BWRVIP-29 and, therefore, following the guidance of BWRVIP-190 is consistent with the GALL Report, which recommends following the guidance of BWRVIP-29 or later revisions.

Exception 4. LRA Section B.2.1.2 states an exception to the "scope of the program" and "detection of aging effects" program elements. The applicant stated that, "Aging of Standby Liquid Control system (SLC) components subject to the sodium pentaborate environment relies on control of SLC poison storage tank water chemistry. The sodium pentaborate solution is not monitored. The makeup water to the tank is monitored in lieu of the sodium pentaborate solution in the storage tank."

As part of its audit, the staff interviewed the applicant's technical personnel to discuss this issue. During the interview, the applicant stated that because of the high concentration of sodium pentaborate contained in the SLC solution, analyses for relative trace impurities based on the

Water Chemistry Program would be ineffective in directly identifying impurities or potential degradation byproducts. In discussions with the applicant's technical personnel, the staff determined that the SLC tank is a closed system from which impurities could only be introduced through makeup water additions. In addition, the applicant's technical personnel stated that the purity of the sodium pentaborate was verified prior to introduction into the SLC system.

The staff reviewed this exception and determined that the applicant will be able to adequately manage aging issues associated with this exception by being able to determine if impurities have been introduced into the SLC system by monitoring the chemistry of makeup water. In addition, the applicant stated that the effectiveness of the Water Chemistry Program will be verified by a one-time inspection of selected SLC system components as part of the One-Time Inspection Program. On this basis, the staff finds this exception acceptable because the applicant is able to monitor the impurities coming into the SLC system and it would verify the effectiveness of the Water Chemistry with a one-time inspection.

Based on its audit, the staff finds that elements one through six of the applicant's Water Chemistry Program, with acceptable exceptions, are consistent with the corresponding program elements of GALL AMP XI.M2 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.2 summarizes operating experience related to the Water Chemistry Program. The applicant stated that in June 1999, HCGS began service of full flow condensate pre-filters in response to high iron concentrations in feedwater. The operation of the pre-filters resulted in reduction in iron concentration to well below the maximum recommended concentrations. The performance of the pre-filters allowed the use of anion underlay, which allowed sulfate concentrations to be maintained at or below desired levels. The applicant stated that the net result of the pre-filter installation was drastically improved reactor water chemistry and lengthened resin bed life.

In additional operating experience descriptions, the applicant noted a trend in increasing condensate demineralizer influent conductivity with an increase in chloride concentration to above recommended values. This increase in chloride prompted an Action Level 1 response of increased monitoring and the implementation of a corrective action plan. As a result of these actions, the applicant identified tube leaks in a waterbox, which were subsequently repaired. The applicant stated that this demonstrated how the Water Chemistry Program is effective in detecting unexpected parameters and in identifying and resolving issues responsible for chemistry beyond acceptable limits.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions.

The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.2 provides the UFSAR supplement for the Water Chemistry Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.1-2, 3.2-2, 3.3-2, and 3.4-2. The staff also notes that the applicant committed (Commitment No. 2) to ongoing implementation of the existing Water Chemistry Program for managing aging of applicable components during the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Water Chemistry Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with the exceptions, is adequate to manage the aging effects for which the LRA credits it. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.2 BWR Stress Corrosion Cracking

Summary of Technical Information in the Application. LRA Section B.2.1.7 describes the existing BWR Stress Corrosion Cracking Program as consistent, with an enhancement, with GALL AMP XI.M7, "BWR Stress Corrosion Cracking." The applicant stated that the BWR Stress Corrosion Cracking Program manages IGSCC in reactor coolant pressure boundary (RCPB) piping and piping components made of austenitic stainless steel and nickel based alloy components. The applicant further stated that the program follows the guidelines in NUREG-0313, Revision 2, and GL 88-01 and its Supplement 1 and includes the following:

- preventive measures to mitigate IGSCC (the applicant has applied mechanical stress Improvement process (MSIP) to several reactor vessel nozzle welds)
- augmented ISI according to BWRVIP-75-A, "BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules"
- flaw evaluation to monitor IGSCC and its effects
- monitoring of reactor coolant water chemistry in accordance with the guidelines in BWRVIP-130, "BWR Water Chemistry Guidelines," to reduce susceptibility to IGSCC (HCGS implemented HWC and NMCA)

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M7. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M7. The staff also conducted onsite interviews with the applicant to confirm these results.

The staff also reviewed the portions of the "preventive actions" program element associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement are as follows.

Enhancement. LRA Section B.2.1.7 states an enhancement to the "preventive actions" program element. The applicant stated that the program will be enhanced to clarify that, for the components within the scope of the BWR Stress Corrosion Cracking Program, resistant materials will be used for new and replacement components. The applicant further stated that this includes low carbon stainless piping and stainless steel weld material limited to a maximum carbon content 0.035 wt. percent and a minimum ferrite content of 7.5 percent.

The staff noted that the "preventive actions" program element in GALL AMP XI.M7 states that the BWRVIP-75 report includes recommendations regarding selection of materials that are resistant to sensitization, use of special processes that reduce residual tensile stresses, and monitoring and maintenance of coolant chemistry. It further states that resistant materials are used for new and replacement components and include low-carbon grades of austenitic stainless steel and weld metal, with a maximum carbon of 0.035 wt. percent and a minimum ferrite of 7.5 percent in weld metal and CASS.

Based on its review, the staff finds the applicant's enhancement acceptable because the applicant will be selecting new and replacement components that include low carbon stainless piping and stainless steel weld material limited to a maximum carbon content 0.035 wt. percent and a minimum ferrite content of 7.5 percent, which is consistent with the recommendations in GALL AMP XI.M7.

Based on its audit, the staff finds that elements one through six of the applicant's BWR Stress Corrosion Cracking Program, with an acceptable enhancement, are consistent with the corresponding program elements of GALL AMP XI.M7 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.7 also summarizes operating experience related to the BWR Stress Corrosion Cracking Program. The applicant stated it has performed inspections of the IGSCC susceptible components and welds as delineated in NUREG-0313, and later modified by GL 88-01 and more recently by BWRVIP-75-A as part of the ASME Section XI ISI program. The applicant also stated that its ISI program identifies 386 augmented components that are inspected in accordance with GL 88-01.

The applicant further stated that the inspections have been successful in detecting flaws in the past. The applicant stated that specifically, during refueling outages RF07, RF12, and RF14, nozzles N5B, N2K, and N2A, respectively, were determined to have flaws in the nozzle welds. The applicant further stated that in each instance, the deficiencies were entered into a corrective action program and corrected in a timely manner. The applicant further stated that subsequent inspection of the repaired nozzles did not detect any flaw indications. The staff noted that these inspections have detected only three flaws that exceeded the IWB-3500 acceptance standards and in each case, the flaws were evaluated, a root cause analysis was performed, and inspections of similar welds were performed to check for additional evidence of cracking.

The staff noted that starting with the initial design and construction of the plant and continuing on through current operations, the applicant has taken numerous actions to reduce the effects of IGSCC on the RCPB components and a partial list is included below:

(1) incorporated recommendations of NUREG-0313, Revision 1 at the time of construction (corrosion resistant materials were used for the RPV safe ends and extensions)

(2) eliminated thermal sleeves in vessel design

(3) applied corrosion resistant cladding to field welds for 304 stainless steel piping connections

(4) heat treated all of the shop welds before installation

(5) applied MSIP to several RPV nozzle welds

(6) implemented HWC and NMCA

(7) improved HWC system availability to over 90 percent

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.7 provides the UFSAR supplement for the BWR Stress Corrosion Cracking Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2.

The staff also notes that the applicant committed (Commitment No. 7) to enhance the BWR Stress Corrosion Cracking Program prior to entering the period of extended operation. Specifically, the applicant committed that for the components within the scope of the BWR Stress Corrosion Cracking Program, resistant materials will be used for new and replacement components. This includes low carbon stainless piping and stainless steel weld material limited to a maximum carbon content 0.035 wt. percent and a minimum ferrite content of 7.5 percent.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's BWR Stress Corrosion Cracking Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that its implementation through Commitment No. 7 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.3 Flow-Accelerated Corrosion

Summary of Technical Information in the Application. LRA Section B.2.1.11 describes the existing Flow-Accelerated Corrosion Program as consistent, with an exception, to GALL AMP XI.M17, "Flow-Accelerated Corrosion." The applicant stated that the Flow-Accelerated Corrosion Program is based on EPRI guidelines in Nuclear Safety Analysis Center (NSAC)-202LR3, "Recommendations for an Effective Flow Accelerated Corrosion Program," and that the program provides for predicting, detecting, and monitoring wall thinning in piping and fittings, valve bodies, and heat exchangers due to flow-accelerated corrosion. The applicant further stated that the program uses the EPRI computer program CHECWORKS, along with the implementing guidelines contained in NSAC-202L-R3, "Recommendations for an Effective Flow Accelerated Corrosion Program."

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M17. The staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M17, with a common exception to the "scope of the program" and "detection of aging effects" program elements. The staff's evaluation of this exception follows.

Exception. LRA Section B.2.1.11 states that there is an exception to the "scope of the program" and "detection of aging effects" program elements. GALL AMP XI.M17 states that the "scope of the program" and "detection of aging effects" program elements of the Flow-Accelerated Corrosion Program relies on implementation of EPRI guidelines in NSAC-202L-R2; however, in the LRA, the applicant stated that the Flow-Accelerated Corrosion Program is based on the EPRI guidelines found in NSAC-202L-R3. The applicant stated that the new revision of the EPRI guidelines incorporate lessons learned and improvements to detection, modeling, and mitigation technologies that became available since NSAC-202L-R2 was published. The staff previously reviewed NSAC-202L-R3 (NUREG-1929, Volume 2) and determined that it is equivalent to NSAC-202L-R2 and in addition, allows the use of the Averaged Band Method, which is another method for determining wear of piping components from UT inspection. The staff notes that EPRI documents are created using industry experience over several years and finds that the Averaged Band Method provides another method to determine the wear of piping components from UT inspections. The staff finds this method to be more accurate, thereby resulting in better prediction of remaining life and less rework. The staff finds the use of NSAC-202L-R3 acceptable because it will continue to allow the applicant to manage wall thinning due to flow-accelerated corrosion on the internal surfaces of carbon and low alloy steel piping and components that contain both single-phase and two-phase high-energy fluids.

Based on its review, the staff finds that elements one through six of the applicant's Flow-Accelerated Corrosion Program, with an acceptable exception, are consistent with the corresponding program elements of GALL AMP XI.M17 and are, therefore, acceptable.

Operating Experience. LRA Section B.2.1.11 summarizes operating experience related to the Flow-Accelerated Corrosion Program. The applicant stated that it implemented a piping replacement plan in 2006, to mitigate wall thinning, by upgrading to flow-accelerated corrosion resistant material. Since implementing the replacement program, the applicant has replaced portions of the piping in the main steam drains, reactor water feed pump turbine steam supply drains, extraction steam lines, seal steam lines, feedwater heater vent lines, reactor core isolation cooling (RCIC) and HPCI steam supply drain lines, and the plant heating system. The piping replacement plan continues to monitor for replacement, the operating vent lines for all the feedwater heaters, the main steam turbine control valve before seat drains and leak-off lines, the main steam lead drains, portions of reactor feed pump turbine steam drains, the steam jet air ejector runoff drain, portions of plant heating piping inside the turbine building steam tunnel, and the turbine bypass seal leak-off lines.

The applicant also provided the following operational experience:

> As result of feedwater heater shell failures at other nuclear plants (OE-9941), as well as Salem Unit 1 plant experience with feedwater heaters (OE11020), feedwater heater shell inspections were instituted at Hope Creek. In 2000, the #5A, B & C feedwater heater shell area was replaced in the vicinity of the extraction steam inlet nozzles. A shell area was cut out of the heaters, and was replaced with carbon steel plate roll-bonded with 0.125" stainless steel cladding on the inside diameter. The extraction steam inlet nozzle was also replaced with the same configuration. All feedwater heaters (except the #1 heaters), have been inspected at least once. The shell area around two of the four #1C feedwater heater extraction steam inlet nozzles were inspected in 2007, and no problem was identified. In a letter dated January 19, 2011, the applicant stated that feedwater heater shell area adjacent to the remaining two extraction steam inlet nozzles for the #1C, and all the #1A and #1B feedwater heaters extraction steam inlet nozzles were inspected in 2010, and no problems were identified.
>
> As a part of the feedwater heater shell FAC [flow-accelerated corrosion] inspection program, stress evaluations are performed to obtain the allowable minimum wall thickness. This minimum allowable thickness is the basis for trending wall thinning and tracking when the next inspection is scheduled. The scope of the feedwater heater shell inspection project is to inspect every feedwater heater shell at least once in the vicinity of the extraction steam inlet nozzle. Wear rates are determined and wall thinning on the feedwater heaters are trended, and analyses are performed to determine appropriate inspections, which are scheduled prior to the shell reaching its minimum allowable wall thickness.
>
> In 2004, the Hope Creek FAC program prompted a wall thickness inspection of feedwater heater nozzles in response to OE17919, "Inspection Identifies Holes in #2 Heater Extraction at LaSalle Unit 1." Based on ultrasonic testing (UT) and

visual inspection, significant wall thinning downstream of the piping/nozzle weld for the #2A feedwater heater nozzles was discovered. Extent of condition evaluation determined that #2B and #2C feedwater heaters had experienced the same kind of wall thinning.

During internal weld repairs in April 2006, it was discovered that the nozzle had a stainless steel liner, which started at about 1/4" downstream of the pipe and nozzle weld, rather than being fully extended. The wall thinning was found to be caused by steam cutting of the nozzle between the inner liner and the outer diameter, indicating the degradation to the nozzle would have been less severe had the liner been fully extended to the top of the nozzle. So far eleven out of the twelve nozzles for the #2 feedwater heaters (FWHs) have been repaired by internal weld build-up. In the January 19, 2011, letter, the applicant stated that all three feedwater heaters were successfully replaced in RF 16 outage (October 2010). The new FWHs have extraction steam inlet nozzles fabricated with alloy steel, which is resistant to FAC. To correct the root cause of this problem, the Hope Creek FAC Program will continue to monitor FAC-susceptible feedwater heater nozzles and make repairs or replacements as warranted.

Extended Power uprate (EPU) at Hope Creek was implemented in 2008. In advance of this power uprate, in 2002, Hope Creek performed a FAC evaluation on CHECWORKS at 20 percent power uprate. Comparing the predicted CHECWORKS wear rates at EPU with wear rates at normal power, this evaluation revealed that the power uprate operating conditions would have a minimal impact on FAC wear rates. Also, results showed that the average predicted wear rate would not cause an increased need for physical modifications or replacements of the systems that are vulnerable to FAC. In 2008, the CHECWORKS model at Hope Creek was revised to reflect the power uprate conditions, in compliance with the EPRI NSAC 202L-R3 Guidelines.

Hope Creek has benefited from FAC related experience of other nuclear plants that have gone through EPU. Hope Creek actively participates in the CHECWORKS User Group (CHUG) and stays informed of the industry experience on FAC. So far, no industry experience has indicated any FAC related issues because of EPU that would have any impact on risk ranking by CHECWORKS. Hope Creek will enter its period of extended operation in 2026. This provides at least 18 years of additional plant experience at EPU conditions. In addition, it allows for monitoring experiences at other nuclear plants that have gone through EPU conditions.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. The staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.11 provides the UFSAR supplement for the Flow-Accelerated Corrosion Program. The staff reviewed this UFSAR supplement description of the program and notes that it does not explicitly conform to the recommended description for this type of program as described in SRP-LR Tables 3.2-2 and 3.4-2. The Flow-Accelerated Corrosion Program description in LRA Section A.2.1.11 does not specifically reference NSAC-202L-R2; however, as noted previously in the review of the AMP, the applicant is using the CHECWORKS program and NSAC-202L-R3 as the basis for the Flow-Accelerated Corrosion Program. The staff also notes that the applicant committed (Commitment No. 11) to ongoing implementation of the existing Flow-Accelerated Corrosion Program for managing aging of applicable components during the period of extended operation.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Flow-Accelerated Corrosion Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception with the justification and determines that the AMP, with the exception, is adequate to manage the aging effects for which the LRA credits it. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.4 Bolting Integrity

Summary of Technical Information in the Application. LRA Section B.2.1.12 describes the existing Bolting Integrity Program as consistent, with an exception and an enhancement, with GALL AMP XI.M18, "Bolting Integrity." The applicant stated that the Bolting Integrity Program incorporates NRC and industry recommendations delineated in NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants;" EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide;" and EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants." The applicant also stated that the Bolting Integrity Program provides for condition monitoring of pressure retaining bolted joints within the scope of license renewal and that the program provides for managing cracking, loss of material, and loss of preload by performing visual inspections for pressure retaining bolted joint leakage in the environments of indoor and outdoor air, raw water, soil, and treated water. The applicant further stated that procurement controls and installation practices defined in plant procedures ensure that only approved lubricants, sealants, and proper torques are applied to bolting within the scope of the program and that the activities are implemented through station procedures.

The applicant stated that: (1) for ASME Code class bolting, the extent and schedule of inspections is in accordance with ASME Code Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1; (2) bolting associated with ASME Code Class 1 vessel, valve, and pump flanged joints receive VT-1 inspection; and (3) for other pressure retaining bolting, routine observations will document any leakage before the leakage becomes excessive. The applicant also stated that the integrity of non-ASME Class 1, 2, and 3 system and component pressure retaining bolted joints is evaluated by detection of visible leakage during maintenance or routine observation such as system walkdowns. The applicant further stated that high-strength bolts (actual yield strength greater than or equal to 150 thousands of pounds per square inch (ksi)) are not used on structural connections and that structural bolting and fasteners (actual yield strength less than 150 ksi) both inside and outside containment are inspected by the Structures Monitoring Program. The applicant identified various other AMPs that also provide or supplement the aging management of bolting and fasteners, including: (1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, IWD; (2) ASME Section XI, Subsection IWE; (3) ASME Section XI, Subsection IWF; (4) Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems; (5) External Surfaces Monitoring; (6) Buried Piping Inspection; and (7) Buried Non-Steel Piping Inspection.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M18. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding elements of GALL AMP XI.M18, with the exception of the "scope of the program" and "preventive actions" program elements. For these elements, the staff determined the need for additional clarification, which resulted in the issuance of RAIs, which are discussed below.

In GALL AMP XI.M18, the "scope of the program" program element states that the Bolting Integrity Program covers bolting within the scope of license renewal, including: (1) safety-related bolting, (2) bolting for NSSS component supports, (3) bolting for other pressure retaining components, including nonsafety-related bolting, and (4) structural bolting (actual measured yield strength greater than or equal to 150 ksi). The "preventive actions" program element states that preventive actions include proper torquing and application of an appropriate preload. Based on its review of the applicant's documentation, the staff noted that aging of component support and structural bolting within the scope of license renewal may not be managed by the applicant's Bolting Integrity Program but instead be managed by other AMPs such as the applicant's Structures Monitoring Program. Also, it was not clear to the staff how the applicant would ensure that all elements of GALL AMP XI.M18 would be included in other AMPs credited to manage bolting not included in the Bolting Integrity Program.

By letter dated May 14, 2010, the staff issued RAI B.2.1.12-01 requesting that the applicant: (1) explain why use of other AMPs to manage the aging effects of component support and structural bolting was not identified as an exception to GALL AMP XI.M18 "scope of the program" program element; and (2) explain how the applicant ensures that other AMPs credited for aging management of component support and structural bolting include the recommendations that are contained in GALL AMP XI.M18 "preventive actions" program element.

In its response dated June 14, 2010, the applicant confirmed its understanding that GALL AMP XI.M18 recommends that component support bolting and structural bolting be included within the scope of the Bolting Integrity Program and that the 10 elements of GALL AMP XI.M18 are applicable to component support bolting and structural bolting within the scope of license renewal. The applicant stated that it did not identify an exception to recommendations in the GALL Report because the recommendations identified in the 10 elements of GALL AMP XI.M18 are implemented through existing station procedures in its Bolting Integrity Program that are applicable to mechanical system closure bolting, as well as to component support bolting and structural bolting. The applicant also stated that the additional AMPs credited for aging management of component support bolting and structural bolting are primarily condition monitoring programs that supplement activities of the Bolting Integrity Program. In its response, the applicant further stated that to ensure continued implementation of all 10 elements of its Bolting Integrity Program through the period of extended operation, the LRA is revised to credit the Bolting Integrity Program for component support bolting and structural bolting in the cranes and hoists system, the fuel handling and storage system, the auxiliary boiler building, the auxiliary building control/diesel generator area, the auxiliary building service/radwaste area, the component supports commodity group, the fire water pump house, the primary containment, the reactor building, the service water intake structures, the switchyard, the turbine building, and the yard structures.

In its response, the applicant provided a number of LRA changes which revised LRA Appendix A, Section A.2.1.12; the UFSAR supplement for the Bolting Integrity Program; and LRA Appendix B, Section B.2.1.12, the summary description for the Bolting Integrity Program, to describe the applicant's Bolting Integrity Program as "an existing program that provides aging management of pressure retaining bolted joints, component support bolting and structural bolting within the scope of license renewal." The applicant also revised a number of bolting-related lines in the Summary of Aging Management Evaluations tables in LRA Section 3. The changes in the LRA summary tables state that the Bolting Integrity Program manages aging effects in component support bolting and structural bolting and that other applicable AMPs include condition monitoring that supplements the Bolting Integrity Program. For affected AMR result lines that had previously cited generic Note E, indicating that an alternative to the AMP recommended in the GALL Report was credited, the applicant added a line item that credited the Bolting Integrity Program and cited generic Note B, indicating that the result is consistent with the GALL Report, but the AMP program elements include some acceptable exception to the GALL Report's recommendations.

In its review of the applicant's RAI response, the staff determined that including component support bolting within the scope of other programs does not constitute an exception to the GALL Report results because station procedures referenced in the applicant's Bolting Integrity Program that are applicable to mechanical system closure bolting are also applicable for component support bolting and structural bolting. The staff also determined that the applicant's changes to the LRA are acceptable because they clarify that alternative condition monitoring AMPs are not used in lieu of, but are used to supplement the mitigation and monitoring elements of the Bolting Integrity Program. The staff finds that the applicant's Bolting Integrity Program is consistent with the recommendations in GALL AMP XI.M18 with regard to the staff's concerns expressed in RAI B.2.1.12-01 and that the applicant's response resolves all issues raised in the RAI.

By letter dated June 1, 2010, the staff issued RAI 3.3.2.3.10-01, related both to the applicant's Buried Piping Inspection Program and the Bolting Integrity Program. The RAI requested the applicant to provide additional details regarding how bolting in buried piping is inspected. In its response dated June 24, 2010, the applicant stated that buried bolts are inspected during directed or opportunistic excavations of buried piping, in addition to a flow test, to confirm that there is no significant leakage from bolted pressure retaining piping joints in accordance with its

Buried Piping Inspection Program. The staff's evaluation of the RAI response is documented in SER Section 3.3.2.3.10.

By letter dated August 3, 2010, the staff issued RAI B.2.1.12-02 requesting that the applicant clarify what pressure joint bolting within the scope of the Bolting Integrity Program is exposed to raw water or treated water environments and to explain how visual inspections are performed to detect loss of preload for submerged bolted joints. In its response dated August 26, 2010, the applicant stated that the pressure retaining bolted joints exposed to raw water are limited to the service water pump bolting and that the submerged portion of the service water pump includes bolted connections attached with aluminum bronze bolts. The applicant further stated that the in-scope pressure retaining bolted joints exposed to treated water are limited to emergency core cooling system (ECCS) suction strainers and connecting piping located in the suppression chamber.

The applicant stated that service water pump bolting is inspected during periodic maintenance, with each service water pump being removed and replaced with a refurbished spare pump on a 10-year frequency. The applicant further stated that during disassembly, the pumps are inspected for loose or missing bolting, that the bolts are inspected for loss of material, and that during reassembly the bolting is torqued in accordance with design specifications to prevent loss of preload.

The applicant stated that: (1) a walkdown and visual inspection of the suppression chamber is performed on an 18-month frequency; (2) this inspection includes observation of submerged ECCS suction strainers, including bolted connections, from the catwalk inside the suppression chamber; and (3) the suppression pool floor and the suction strainers are inspected for loose objects and debris, including any bolting that may have become unattached. The applicant further stated that the submerged suppression pool shell is subject to periodic ISI in accordance with ASME Code Section XI requirements by divers certified to perform VT-1 and VT-3 inspections and that during this activity, the divers also inspect the submerged ECCS suction strainers and associated piping for general condition, debris accumulation, and mechanical damage.

In its response to RAI B.2.1.12-02, the applicant submitted changes that provide additional details in LRA Sections A.2.1.12 and B.2.1.12, the UFSAR supplement and the program evaluation, respectively, for the Bolting Integrity Program. In both LRA sections, the changes add a statement that the aging management activities directed by the Bolting Integrity Program include visual inspections for pressure retaining bolted joint leakage and preventive measures implemented during bolted joint maintenance and installation. In addition, in LRA Section B.2.1.12, the applicant added statements that normally inaccessible bolted connections are inspected for degradation when they are made accessible during maintenance activities and that inspection activities for submerged bolting are performed in conjunction with associated component maintenance activities.

The staff notes that the applicant's aging management activities for all submerged bolting within the scope of license renewal includes inspection of the submerged bolts and bolted joints on a frequency determined by periodic maintenance or inspection of associated components. The staff finds this feature of the Bolting Integrity Program acceptable because periodic inspections provide opportunity for the applicant to find, evaluate, and correct any degraded conditions associated with submerged bolting before failure of the bolting to perform its intended function occurs. The staff also finds the applicant's changes to the LRA acceptable because they provide additional detail and clarification describing implementation of the Bolting Integrity

Program. On this basis, the staff finds that the applicant's response to RAI B.2.1.12-02 resolves all issues addressed in the RAI.

The staff also reviewed the portions of the "monitoring and trending" and the "corrective actions" program elements associated with the exception and the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the exception and enhancement follows.

Exception. LRA Section B.2.1.12 states an exception to the "monitoring and trending" program element. The applicant stated that the GALL Report indicates that if a bolting connection for pressure retaining components (not covered by ASME Code Section XI) is reported to be leaking, then it may be inspected daily and that, if the leak rate does not increase, the inspection frequency may be decreased to biweekly or weekly. The applicant stated that it uses its corrective action program to determine an appropriate inspection frequency for identified leaks in bolting connections.

The applicant provided justification for this exception by stating that for other than ASME Classes 1, 2, or 3 bolting, it uses its corrective action program to document and manage locations where leakage is identified during routine observations, including engineering walkdowns and equipment maintenance activities. The applicant stated that based on the severity of the leak and the potential to impact plant operations and nuclear or industrial safety, a leak will be repaired immediately, scheduled for repair, or monitored for change. The applicant stated that if the leak rate changes (increases, decreases, or stops) the monitoring frequency is re-evaluated and may be revised and that its operating experience has not indicated a need for a set frequency (e.g., daily) of leakage inspections involving bolting.

The staff noted that the applicant's corrective action program is consistent with the requirements of 10 CFR 50, Appendix B and includes provisions for reporting, documenting, evaluating safety significance, trending, and implementing corrective actions for bolted pressure boundary components reported to be leaking. Because the applicant's corrective action program is consistent with 10 CFR 50, Appendix B and has provisions to determine an appropriate inspection frequency for a bolted pressure boundary component found to be leaking, the staff finds the applicant's exception to be acceptable.

Enhancement. The applicant stated that prior to the period of extended operation the "corrective actions" program element will be revised to state that the following bolts and nuts should not be reused: (a) galvanized bolts and nuts, (b) ASTM A490 bolts, and (c) any bolts and nuts tightened by the turn-of-nut method.

The staff noted that the applicant's enhancement to its Bolting Integrity Program is listed as Commitment No. 12 in LRA Table A.5, License Renewal Commitment List. The staff also noted that the applicant's proposed enhancement is consistent with EPRI TR-104213, Section 16.11.2, which provides recommendations regarding bolting material that should not be reused. On the basis that guidelines in EPRI TR-104213 are endorsed by GALL AMP XI.M18, and the applicant's enhancement is consistent with a recommendation in the EPRI guidance document and is listed in the applicant's License Renewal Commitment List, the staff finds the applicant's enhancement to its Bolting Integrity Program to be acceptable.

Based on its audit and review of the applicant's responses to RAIs B.2.1.12-01 and B.2.1.12-02, the staff finds that elements one through six of the applicant's Bolting Integrity program, with an acceptable exception and an enhancement, are consistent with the corresponding program elements of GALL AMP XI.M18 and, therefore, the staff finds it acceptable.

Operating Experience. LRA Section B.2.1.12 summarizes operating experience related to the Bolting Integrity Program. The applicant stated that it has experienced isolated cases of bolt corrosion, loss of bolt preload, and bolt torquing issues, and that in all cases, the existing inspection and testing methodologies have discovered the deficiencies and corrective actions were implemented prior to loss of system or component intended functions. The applicant also stated that in 2004, an inspection of the torus lateral seismic restraint bolting washers showed scaling and that after the scale was removed, pitting was found on the washers. The applicant further stated that the corrective action was to remove scaling from all washers and apply a protective coating and that follow-up inspections have not found any rust or scaling.

The applicant stated that in 2004, during a system walkdown, a bolt was found to be missing on a nonsafety-related pipe support base plate in the safety auxiliaries cooling system (SACS) and that further investigation determined that the bolt was in place but rusted. The applicant also stated that an engineering evaluation determined that operability of the SACS was not affected and that new bolts were installed and properly torqued. The applicant further stated that these examples demonstrate that problems are discovered before intended function is affected and that corrective actions are taken to prevent recurrence.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion of SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.12 provides the UFSAR supplement for the Bolting Integrity Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.1-2, 3.2-2, 3.3-2, and 3.4-2. The staff also notes that the applicant committed (Commitment No. 12) to enhance the Bolting Integrity Program prior to entering the period of extended operation. Specifically, the applicant committed to enhance the Bolting Integrity Program prior to the period of extended operation to include a requirement that the following bolts and nuts should not be reused: (1) galvanized bolts and nuts, (2) ASTM A490 bolts, and (3) any bolts and nuts tightened by the turn-of-nut method. The GALL AMP XI.M18 endorses EPRI TR-104213 which recommends that these nuts and bolts should not be reused.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Bolting Integrity Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the aging effects for which the LRA credits it. Also, the staff reviewed the enhancement and confirmed that its implementation through Commitment No. 12 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it is compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.5 Closed-Cycle Cooling Water System

Summary of Technical Information in the Application. LRA Section B.2.1.14 describes the existing Closed-Cycle Cooling Water Program as consistent, with an exception and enhancements, with GALL AMP XI.M21, "Closed-Cycle Cooling Water System." The applicant stated that the Closed-Cycle Cooling Water Program manages the aging of piping, piping components, piping elements, and heat exchangers. The applicant also stated that its program incorporates mitigation, including addition of corrosion inhibitors, the use of water purity standards based on EPRI TR-1007820, and monitoring activities including inspections and NDEs for heat exchangers exposed to closed-cycle cooling water. The applicant further stated that it monitors performance trends of system pumps and heat exchangers to determine if or when any corrective actions are required and that it will perform a one-time inspection of low or stagnant flow areas to verify the effectiveness of the Closed-Cycle Cooling Water Program in mitigating aging effects in these areas.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M21. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M21.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements associated with the exception and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this exception and these enhancements are as follows.

Exception. LRA Section B.2.1.14 states an exception to the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. The applicant stated that it will implement the guidance provided in EPRI TR-1007820, which is the 2004 Revision to EPRI TR-107396, which is the report recommended by GALL AMP XI.M21. The applicant also stated that the new revision provides more prescriptive guidance, has a more conservative monitoring approach, and meets the same requirements of TR-107396 for effectively managing loss of material, cracking, and reduction of heat transfer.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception because the EPRI Closed Cooling Water Chemistry Guidelines have been updated from the version cited in the GALL Report. The staff finds this exception acceptable because the newer version of the above EPRI guidelines contains more recent operating experience information and applies a more conservative approach to managing aging than the previous version.

Enhancement 1. LRA Section B.2.1.14 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. The applicant stated that new recurring tasks will be established for enhancing the performance monitoring of the closed-cycle cooling water system.

During the onsite audit, the staff interviewed HCGS technical staff, which indicated that the applicant would establish new recurrent tasks as enhancements to the performance monitoring of the closed-cycle cooling water system. On the basis of this review, the staff finds this enhancement acceptable because performance monitoring demonstrates system operability and confirms program effectiveness, and when it is implemented (Commitment No. 14), it will make the program consistent with the recommendations in GALL AMP XI.M21.

Enhancement 2. LRA Section B.2.1.14 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. The applicant stated that new recurring tasks will be established for enhancing the performance monitoring of the chilled water system.

During the onsite audit, the staff interviewed HCGS technical staff, which indicated that the applicant would establish new recurrent tasks as enhancements to the performance monitoring of the chilled water system. On the basis of this review, the staff finds this enhancement acceptable because performance monitoring demonstrates system operability and confirms program effectiveness, and when it is implemented (Commitment No. 14), it will make the program consistent with the recommendations in GALL AMP XI.M21.

Enhancement 3. LRA Section B.2.1.14 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. The applicant stated that a one-time inspection of selected Closed-Cycle Cooling Water Program components in low or stagnant flow areas will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water Program. The applicant also stated that these inspections will be performed prior to the period of extended operation.

During the onsite audit, the staff interviewed HCGS technical staff, which indicated that the applicant would establish one-time inspections of selected Closed-Cycle Cooling Water Program components in low or stagnant flow areas. On the basis of this review, the staff finds this enhancement acceptable because it will ensure the effectiveness of the program since the control of water chemistry does not preclude corrosion at low or stagnant flow locations, and when it is implemented (Commitment No. 14), it will make the program consistent with the recommendations in GALL AMP XI.M21.

Enhancement 4. LRA Section B.2.1.14 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. The applicant stated that a one-time inspection of selected chemical mixing tanks and associated piping in the Closed-Cycle Cooling Water Program will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water Program on the interior surfaces of the tanks and associated piping.

During the onsite audit, the staff interviewed HCGS technical staff, which indicated that the applicant would establish one-time inspections of selected Closed-Cycle Cooling Water Program mixing tanks and associated piping. On the basis of this review, the staff finds this enhancement acceptable because it will ensure the effectiveness of the chemistry controls, and when it is implemented (Commitment No. 14), it will make the program consistent with the recommendations in GALL AMP XI.M21.

Enhancement 5. LRA Section B.2.1.14 states an enhancement to the “preventive actions,” “detection of aging effects,” and “monitoring and trending” program elements. The applicant stated that the program will be enhanced such that the plant auxiliary building chilled water system, which is part of the control area chilled water system, will comply with the pure water control program in accordance with EPRI TR-1007820 prior to the period of extended operation.

During the onsite audit, the staff interviewed HCGS technical staff, which indicated that the applicant would identify consequences resulting from changes to the control area chilled water system to bring it into compliance with EPRI TR-1007820. On the basis of this review, the staff finds this enhancement acceptable because implementation of the EPRI guidelines will ensure satisfactory control of corrosion in pure water systems, and when it is implemented (Commitment No. 14), it will make the program consistent with the recommendations in GALL AMP XI.M21.

Enhancement 6. LRA Section B.2.1.14 states an enhancement to the “parameters monitored or inspected,” “detection of aging effects,” and “monitoring and trending” program elements. The applicant stated that a one-time inspection of selected control area chilled water system components, including the plant auxiliary building chilled water system, will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water Program. The applicant stated that these inspections will be performed prior to the period of extended operation.

During the onsite audit, the staff interviewed HCGS technical staff, which indicated that the applicant would establish one-time inspections of selected control area chilled water system components, including the auxiliary building chilled water system. On the basis of this review, the staff finds this enhancement acceptable because it will ensure the effectiveness of the chemistry controls, and when it is implemented (Commitment No. 14), it will make the program consistent with the recommendations in GALL AMP XI.M21.

Based on its audit, the staff finds that elements one through six of the applicant’s Closed-Cycle Cooling Water Program, with an acceptable exception and acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.M21 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.14 summarizes operating experience related to the Closed-Cycle Cooling Water Program. The applicant stated that during a monthly surveillance test of the emergency diesel generator (EDG), a higher than normal lube oil temperature was observed. The applicant also stated that an investigation was performed, which identified the increase in temperature was due to an improperly positioned throttle valve that had been adjusted during recent safety auxiliaries cooling system flow balancing. The applicant further stated that the elevated temperatures in the EDG did not result in any material degradation and that this was an example of the effectiveness of monthly surveillance tests.

The applicant stated that several action reports were generated as a result of elevated metal contaminants in the diesel generator jacket water. The applicant also stated that it performed further investigations and determined that the cause of the elevated metal contaminants was the long-term reuse of the jacket water after maintenance. As a result, the applicant stated that it now uses a new corrosion inhibitor, which has resulted in significantly fewer incidents of metal contaminants in the diesel jacket water.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.14 provides the UFSAR supplement for the Closed-Cycle Cooling Water Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.1-2, 3.2-2, 3.3-2, and 3.4-2.

The staff also notes that the applicant committed (Commitment No. 14) to enhance the Closed-Cycle Cooling Water Program prior to entering the period of extended operation. Specifically, the applicant committed to: (1) establish new recurring tasks to enhance the performance monitoring of the closed-cycle cooling water and chilled water systems; (2) perform one-time inspections of selected components in low or stagnant flow areas and interior surfaces of selected chemical mixing tanks and associated piping; (3) implement a pure water control program; and (4) perform a one-time inspection of selected components for the control area chilled water system.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d)

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Closed-Cycle Cooling Water Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the aging effects for which the LRA credits it. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 14 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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

reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.6 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

Summary of Technical Information in the Application. LRA Section B.2.1.15 describes the existing Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program with enhancements as consistent with GALL AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems." The applicant stated that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program manages loss of material for all cranes, trolley and hoist structural components, fuel handling systems and applicable rails that are within the scope of license renewal. The applicant also stated that visual inspections will be used to assess the conditions such as loss of material due to corrosion and visible signs of wear.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M23. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding element of GALL AMP XI.M23.

The staff also reviewed the portions of the "detection of aging effects" program element associated with the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the enhancements follows.

Enhancement 1. LRA Section B.2.1.15 states that an enhancement will be made to the "scope of the program" and "parameters monitored or inspected" program elements. The applicant stated in the LRA that this enhancement expands on the existing program element by adding visual inspection of structural components and structural bolts for loss of material due to general corrosion, pitting, and crevice corrosion and structural bolting for loss of preload due to self-loosening. The GALL Report "scope of the program" program element states that, "The program manages the effects of general corrosion on the crane and trolley structural components for those cranes that are within the scope of 10 CFR 54.4, and the effects of wear on the rails in the rail system." The GALL Report "parameters monitored or inspected" program element states that the program evaluates the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes. The staff finds this enhancement to be acceptable because it makes this existing program consistent with the GALL Report and expands on the program elements to make them more specific.

Enhancement 2. LRA Section B.2.1.15 states that an enhancement will be made to the "scope of the program" and "parameters monitored or inspected" program elements. The applicant stated that this enhancement expands on the existing program element by adding the requirement for visual inspection of the rails and the rail system for loss of material due to wear. The GALL Report "scope of the program" program element states that, "The program manages the effects of general corrosion on the crane and trolley structural components for those cranes that are within the scope of 10 CFR 54.4, and the effects of wear on the rails in the rail system." The GALL Report "parameters monitored or inspected" program element states that the program evaluates the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes. The staff finds this enhancement to be acceptable because it makes this existing program consistent with the GALL Report and expands on the program elements to make them more specific.

Enhancement 3. LRA Section B.2.1.15 states that an enhancement will be made to the "acceptance criteria" program element. The applicant stated that this enhancement expands on the existing program element by adding the requirement for evaluation of significant loss of material due to corrosion for structural components and structural bolts, and significant loss of material due to wear of rails in the rail system. The GALL Report "acceptance criteria" program element states, "Any significant visual indication of loss of material due to corrosion or wear is evaluated according to applicable industry standards and good industry practice." The staff finds this enhancement to be acceptable because it makes this existing program consistent with the GALL Report.

Based on its audit, the staff finds that elements one through six of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.M23 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.15 summarizes operating experience related to the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program. The applicant stated that no occurrences of unacceptable corrosion for components within the scope of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program have been identified. Additionally, the applicant stated that since HCGS cranes, hoists, trolleys, and fuel handling equipment have not been operated outside their design limits nor beyond their design lifetime, no fatigue-related structural failures have occurred.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff identified no operating experience which could indicate that the applicant's program may not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion of SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.15 provides the UFSAR supplement for the Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.3-2.

The staff also notes that the applicant committed (Commitment No. 15) to enhance the Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program prior to entering the period of extended operation. Specifically, the applicant committed to use the existing program for license renewal and to inspect for loss of material due to corrosion or rail wear.

The staff determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation through Commitment No. 15 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.7 Fire Protection

Summary of Technical Information in the Application. LRA Section B.2.1.17 describes the Fire Protection Program as an existing program that is consistent, with an exception and enhancements, with GALL AMP XI.M26, "Fire Protection." The applicant stated that the program manages the effects of aging for fire barriers, diesel fire pumps, fuel oil supply lines, the halon and carbon dioxide (CO_2) systems, and associated components, through the use of periodic inspections and functional testing to detect aging effects prior to loss of intended functions. The applicant also stated that the program provides for: (1) visual inspections of fire barrier penetration seals for signs of degradation (e.g., change in material properties, loss of materials, cracking, and hardening); (2) visual examinations of the barrier walls, ceilings, and floors in structures within the scope of license renewal at a frequency of once each refueling outage; and (3) periodic visual and functional tests to manage the aging effects of fire doors and dampers and the external surfaces of the halon and CO_2 fire suppression system components. The applicant further stated that performance tests of the diesel driven fire pump will be used to provide data for trending purposes and to detect degradation (corrosion) of the fuel supply lines before the loss of the component intended function occurs.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M26. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding elements of GALL AMP XI.M26, with the exception of the "detection of aging effects" and "acceptance criteria" program elements. For these elements, the staff determined the need for additional clarification, which resulted in the issuance of RAIs.

The "detection of aging effects" program element of GALL AMP XI.M26 recommends that visual inspections of the halon and CO_2 fire suppression systems be performed to detect any sign of degradation, such as corrosion, mechanical damage, or damage to dampers, and that a periodic functional test and inspection be performed at least once every 6 months. The "acceptance criteria" program element of GALL AMP XI.M26 recommends that any sign of corrosion or mechanical damage of the halon and CO_2 fire suppression systems be considered unacceptable. During its review of the program basis document and procedures used to verify the operation of the total flooding CO_2 system, the staff noted that there were no visual inspection activities to check for degradation, such as corrosion or mechanical damage. The staff also noted that the acceptance criteria identified in the procedure did not address corrosion.

By letter dated May 14, 2010, the staff issued RAI B.2.1.17-2 requesting that the applicant confirm how this is considered consistent with GALL AMP XI.M26, and if it is not, justify why this is not an exception or an enhancement.

In its response dated June 14, 2010, the applicant added an additional enhancement to the program and stated that the Fire Protection Program will be enhanced to include visual inspection activities to check for degradation during performance of the halon and CO_2 fire suppression system functional tests. The staff's evaluation of this enhancement is addressed under Enhancement 3.

The staff also reviewed the portions of the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with the exception and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the exception and enhancements follows.

Exception. LRA Section B.2.1.17 states an exception to the "parameters monitored or inspected" and "detection of aging effects" program elements. The exception states that the halon and CO_2 fire suppression systems currently undergo functional testing every refueling cycle (18 months). The "parameters monitored or inspected" and "detection of aging effects" program elements of GALL AMP XI.M26 recommend that periodic visual inspections and functional testing be performed at least once every 6 months to examine halon and CO_2 fire suppression systems for signs of degradation.

The applicant stated that in addition to the 18-month functional testing, the halon fire suppression system is subject to visual inspections for system charge (storage tank weight) every 6 months, and the low-pressure CO_2 fire suppression system is subject to weekly visual storage tank level and pressure checks. The applicant also stated that these test and inspection frequencies are considered sufficient to ensure system availability and operability based on the station operating history (e.g., corrective actions, completed surveillance test results) that shows no aging related events have been found that have adversely affected system operation.

The staff reviewed the applicant's CLB and confirmed that functional testing of the halon and CO_2 fire suppression systems is performed once every 18 months. The staff also reviewed plant operating experience reports and did not find any evidence of age-related degradation in the halon or CO_2 systems. However, during review of the applicant's procedures referenced in the program basis document, the staff noted that neither the 6-month inspection for system charge nor the weekly inspection for tank level and pressure include inspection for signs of degradation, such as corrosion or damper damage, as recommended by GALL AMP XI.M26 for the visual inspections. Therefore, it was not clear to the staff if the exception applied to both the functional testing and visual inspections or to only the functional testing.

By letter dated May 14, 2010, the staff issued RAI B.2.1.17-1 requesting that the applicant clarify whether the exception applies to both functional testing and visual inspections or only applies to functional testing, which would indicate that the Fire Protection Program performs visual inspections at least once every 6 months for signs of degradation of the halon and CO_2 fire suppression systems. If the visual inspection is not performed once every 6 months, the staff also requested that the applicant justify why this is not an exception to GALL AMP XI.M26.

In its response dated June 14, 2010, the applicant stated that the GALL Report recommended visual inspections for corrosion and mechanical damage be performed during the system functional tests and that this exception was intended to apply to both the functional testing and the visual inspection frequencies. The applicant revised the exception to state that the halon and CO_2 fire suppression systems currently undergo functional testing and inspection every refueling cycle (18 months).

The staff finds the exception to visually inspect and functionally test the halon and CO_2 suppression systems once every 18 months acceptable because the applicant is performing inspections and testing in accordance with its CLB. Plant operating experience has shown that the testing frequency is adequate to maintain system function. Visual inspections for system charge (storage tank weight) are performed every 6 months, and the CO_2 fire suppression system storage tank level and pressure are checked weekly.

Enhancement 1. LRA Section B.2.1.17 states an enhancement to the “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements. In the enhancement, the applicant stated that it will expand on the existing program elements by providing additional inspection guidance to identify degradation of fire barrier walls, ceilings, and floors for aging effects, such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. The staff confirmed that the applicant included this enhancement as Commitment No. 17 in LRA Appendix A, Table A.5.

This enhancement, when implemented, will make the Fire Protection Program consistent with GALL AMP XI.M26, which recommends that visual inspection of the fire barrier walls, ceilings, and floors be examined for any sign of degradation, such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. Based on its review, the staff finds the enhancement acceptable because it will make the program consistent with the GALL Report.

Enhancement 2. LRA Section B.2.1.17 states an enhancement to the “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements to expand on the existing program elements by providing specific guidance for examining the exposed external surfaces of the fire pump diesel fuel oil supply line for corrosion during pump tests. The staff confirmed that the applicant included this enhancement as Commitment No. 17 in LRA Appendix A, Table A.5.

The staff notes that this enhancement, when implemented, will make the Fire Protection Program consistent with GALL AMP XI.M26, which recommends that performance of the fire pump is monitored during the periodic test to detect any signs of degradation in the fuel supply lines and to provide data for trending, and that the acceptance criteria include that no corrosion is acceptable in the fuel supply line for the diesel driven fire pump. Based on its review, the staff finds the enhancement acceptable because it will make the program consistent with the GALL Report.

Enhancement 3. By letter dated June 14, 2010, the applicant added an enhancement to the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements to enhance the halon and CO_2 fire suppression system functional test to include: (1) visual inspection of system piping and component external surfaces for signs of corrosion or other age-related degradation, and for mechanical damage; and (2) acceptance criteria stating that identified corrosion or mechanical damage will be evaluated, with corrective action taken as appropriate. The staff confirmed that the applicant included this enhancement in a revision to Commitment No. 17 in LRA Appendix A, Table A.5.

The staff notes that this enhancement, when implemented, will make the Fire Protection Program consistent with GALL AMP XI.M26, which recommends that visual inspections of the halon and CO_2 fire suppression system be performed to detect any sign of degradation, such as corrosion, mechanical damage, or damage to dampers, and that any signs of corrosion or mechanical damage of the halon and CO_2 fire suppression system should be considered unacceptable. Based on its review, the staff finds the enhancement acceptable because it will make the program consistent with the GALL Report.

Based on its audit and review of the applicant's responses to RAIs B.2.1.17-1 and B.2.1.17-2, the staff finds that elements one through six of the applicant's Fire Protection Program, with acceptable exception and enhancements, are consistent with the corresponding program elements of GALL AMP XI.M26 and, therefore, the staff finds it acceptable.

Operating Experience. LRA Section B.2.1.17 summarizes operating experience related to the Fire Protection Program. The applicant stated that during routine fire door inspections using existing surveillance procedures, rust and corrosion were found on the exterior door surface and lower door frame of a fire door and that the door and frame were repaired and painted satisfactorily. The applicant also stated that in September 2006, the CO_2 system fire dampers failed to reposition as required during a simulated functional test due to failure of an electronic signal that prevented an electronic relay from latching and that the applicant replaced the defective electronic control board and retested the system satisfactorily. The applicant further stated that in January 2006, a fire barrier was found damaged, so the applicant inspected areas in the vicinity of the damage to determine if any additional areas were affected and repaired the fireproofing material to acceptable conditions.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.1.17, as amended by letter dated June 14, 2010, provides the UFSAR supplement for the Fire Protection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.3-2. The staff also notes that the applicant committed (Commitment No. 17) to enhance the Fire Protection Program prior to entering the period of extended operation. Specifically, the applicant committed to enhance: (1) the routine inspection procedures to provide additional inspection guidance to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates; (2) the fire pump supply line functional tests to provide specific guidance for examining exposed external surfaces of the fire pump diesel fuel oil supply line for corrosion during pump tests; and (3) the halon and CO_2 fire suppression system functional test procedures to include visual inspection of system piping and component external surfaces for signs of corrosion or other age-related degradation, and for mechanical damage, and to include acceptance criteria stating that identified corrosion or mechanical damage will be evaluated, with corrective action taken as appropriate.

The staff determines that the information in the UFSAR supplement, as amended by letter dated June 14, 2010, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Fire Protection Program and the applicant's responses to the staff's RAIs, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the aging effects for which the LRA credits it. The staff also reviewed the enhancements and confirmed that their implementation through Commitment No. 17 prior to the period of extended operation will make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.8 Fire Water System

Summary of Technical Information in the Application. LRA Section B.2.1.18 describes the existing Fire Water System Program as consistent, with enhancements, with GALL AMP XI.M27, "Fire Water System." The applicant stated that the program manages aging for the water-based fire protection systems through periodic inspections, monitoring, and performance testing and that system functional tests, flow tests, flushes, and inspections are performed in accordance with the applicable guidance from National Fire Protection Association (NFPA) codes and standards. The applicant also stated that the program includes fire system main header flow tests, sprinkler system inspections, yard hydrant visual inspections, fire hydrant hose inspections, hydrostatic tests, gasket inspections, volumetric inspections, fire hydrant flow tests, and pump capacity tests performed periodically to assure that loss of material due to corrosion, microbiologically-influenced corrosion (MIC), or biofouling are managed such that the system intended functions are maintained. The applicant further stated that selected portions of the fire protection system piping, located aboveground and exposed to water, will be inspected by non-intrusive volumetric examinations to ensure that aging effects are managed and that wall thickness is within acceptable limits.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M27. As discussed in the audit report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M27.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "acceptance criteria," and "corrective actions" program elements associated with the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.18 states an enhancement to the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements to inspect selected portions of the water-based fire protection system piping located aboveground and exposed internally to fire water using non-intrusive volumetric examinations. The applicant stated that these inspections will be performed prior to the period of extended operation and every 10 years thereafter. The staff confirmed that the applicant included this enhancement as Commitment No. 18 in LRA Appendix A, Table A-5.

GALL AMP XI.M27 recommends that wall thickness evaluations of fire protection piping be performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion and that these inspections be performed before the end of the current operating term and at plant-specific intervals thereafter, during the period of extended operation. The staff finds this enhancement acceptable because performing non-intrusive examinations on the aboveground fire water piping every 10 years will make the program consistent with the recommendations in GALL AMP XI.M27.

Enhancement 2. LRA Section B.2.1.18 states an enhancement to the "detection of aging effects" program element to replace or perform 50-year sprinkler head inspections and testing using the guidance of NFPA-25, "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (2002 Edition), Section 5-3.1.1. The applicant stated that these inspections will be performed by the 50-year inservice date and every 10 years thereafter. The staff confirmed that the applicant included this enhancement as Commitment No. 18 in LRA Appendix A, Table A-5.

GALL AMP XI.M27 recommends that sprinkler heads be inspected before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter, during the period of extended operation. The staff finds this enhancement acceptable because it will make the program consistent with the recommendations in GALL AMP XI.M27.

Based on its audit, the staff finds that elements one through six of the applicant's Fire Water System Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.M27 and, therefore, the staff finds it acceptable.

Operating Experience. LRA Section B.2.1.18 summarizes operating experience related to the Fire Water System Program. The applicant stated that during routine monthly fire hydrant inspections in August 2001, water was found in the barrel of a hydrant that could not be drained and, therefore, the applicant replaced the hydrant with a new unit. The applicant inspected other hydrants, and none were found to have a leaking barrel. The applicant also stated that the motor-driven fire pump discharge flow became unstable during routine capacity testing in May 2002, so the applicant terminated the testing and performed troubleshooting that revealed the temporary startup strainer was still installed in the suction line leading to the pump and had become fouled. The applicant further stated that the startup strainer was removed, and all other fire pumps on site were inspected with no other startup strainers found installed.

The applicant stated that the fire protection system manager has performed visual inspections of piping internal conditions when exposed during maintenance activities, and observed the piping internals to be in good condition with no significant internal fouling or corrosion buildup. The applicant also stated that the external piping condition is also routinely inspected and maintained by station procedures.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions.

The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. In LRA Section A.2.1.18, the applicant provided the UFSAR supplement for the Fire Water System Program. The staff reviewed this UFSAR supplement description of the program and noted that it conforms to the recommended description for this type of program, as described in SRP-LR Table 3.3-2. The staff also notes that the applicant committed (Commitment No. 18) to enhance the Fire Water System Program prior to entering the period of extended operation. Specifically, the applicant committed to enhance the program to: (1) inspect selected portions of the water-based fire protection system piping located aboveground by non-intrusive volumetric examinations; these inspections shall be performed prior to the period of extended operation and will be performed every 10 years thereafter; (2) replace or perform 50-year sprinkler head inspections and testing using the guidance of NFPA-25, "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (2002 Edition), Section 5-3.1.1. These inspections will be performed prior to the 50-year inservice date and every 10 years thereafter.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Fire Water System Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 18 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.9 Aboveground Steel Tanks

Summary of Technical Information in the Application. LRA Section B.2.1.19 describes the existing Aboveground Steel Tanks Program as consistent, with enhancements, with GALL AMP XI.M29, "Aboveground Steel Tanks." The applicant stated that the Aboveground Steel Tanks Program will be used to manage loss of material for the outdoor carbon steel tanks used for fire protection system water, fire diesel fuel oil, and CO_2 pressurized gas. The applicant also stated that this is a condition monitoring program and it credits the application of paint and coatings to the external surfaces of the in-scope tanks as a corrosion prevention measure, and that the condition of the painted or coated external surfaces, as well as the condition of any exposed base metal, is monitored by this program. The applicant further stated that thickness measurements of the bottom of the fire water storage tank, the only in-scope tank in contact with the ground, will be conducted. The staff notes that the applicant's inspection procedures ensure that the caulk/sealant joint between the tank and foundation interface is visually inspected during the inspection of the tank.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M29. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M29.

The staff also reviewed the portions of the "preventive actions," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.19 states an enhancement to the "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. The applicant stated that the program will be enhanced (Commitment No. 19) to require UT to obtain tank wall thickness measurements for the fire water storage tank. The applicant also stated that these measurements will be monitored and trended and the results would be evaluated against design thickness and the corrosion allowance.

The staff reviewed this enhancement against the corresponding program elements in GALL AMP XI.M29. On the basis of its review, the staff finds this enhancement acceptable because UT provides direct, quantitative measurement of the tank bottom thickness and this method addresses the GALL Report recommendation for an acceptable verification program to consist of thickness measurement of the tank bottom surface, evaluation of measurements against design thickness and corrosion allowance, and trended results.

Enhancement 2. LRA Section B.2.1.19 states an enhancement to the “preventive actions,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements. The applicant stated that the program will be enhanced to provide routine visual inspections of the external surfaces of the in-scope tanks including removal of insulation from the fire water storage tank. The applicant also stated that the inspections will be performed to detect degraded paint and coatings and any resulting metal degradation.

The staff reviewed this enhancement against the corresponding program elements in GALL AMP XI.M29. On the basis of its review, the staff finds this enhancement acceptable because it will provide adequate monitoring of the external surfaces of in-scope tanks, and the routine visual inspection methods address the GALL Report recommendation for periodic system walkdowns to monitor degradation of the protective paint or coating.

Based on its audit, the staff finds that elements one through six of the applicant’s Aboveground Steel Tanks Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.M29 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.19 summarizes operating experience related to the Aboveground Steel Tanks Program. The applicant provided two examples of operating experience related to early detection of corrosion on steel tank surfaces through its routine visual inspections. In one example, the applicant stated that degraded coating and minor corrosion on the exposed surface of a fire water storage tank was detected during a walkdown associated with a semi-annual fire protection inspection. The applicant also stated that no leakage was observed and, based on an engineering evaluation, the integrity of the tank was not impacted. The applicant further stated that the deficient condition was entered into the corrective action program, and repairs were performed. In another instance of operating experience, the applicant described how corrective action was prompted when deteriorated paint was detected by routine visual inspection of a diesel fuel oil day tank. The applicant stated that the deficient condition was entered into the corrective action program and repairs were performed.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant’s program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant’s program demonstrates that it can adequately manage the detrimental effects of aging on SCCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.19 provides the UFSAR supplement for the Aboveground Steel Tanks Program.

The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.3-2 and 3.4-2. The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The staff also notes that the applicant committed (Commitment No. 19) to enhance the Aboveground Steel Tanks Program prior to entering the period of extended operation. Specifically, the applicant committed to include internal UT measurements of the wall thickness on the bottom of the fire water storage tanks, and these measurements will be monitored, trended, and evaluated against design thickness and corrosion allowance to ensure that significant degradation does not occur. The program will also be enhanced to provide routine visual inspections of tank external surfaces, including removal of tank insulation from the fire water storage tank, to detect degraded paint and coatings and any resulting metal degradation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Aboveground Steel Tanks Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 19 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.10 Fuel Oil Chemistry

Summary of Technical Information in the Application. LRA Section B.2.1.20 describes the existing Fuel Oil Chemistry Program as consistent, with exceptions and enhancements, with GALL AMP XI.M30, "Fuel Oil Chemistry." The applicant stated that the Fuel Oil Chemistry Program includes preventive activities to provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of license renewal, to prevent loss of material. The program includes procedures for testing and maintaining the quality of stored and new fuel oil, inspection of the fuel oil storage tanks, and a one-time sample inspection (under the One-Time Inspection Program) of components in systems that contain fuel oil.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M30. For these elements, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

The staff also reviewed the portions of the "scope of the program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with exceptions and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions and enhancements follows.

Exception 1. LRA Section B.2.1.20 states exceptions to the "scope of the program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. The GALL Report AMP recommends periodic sampling of tanks in accordance with the manual sampling standards of ASTM D 4057-95 (2000). The applicant stated that the 280-gallon diesel fire pump fuel oil tank (T-565) samples are single point samples obtained from the tank drain line located off of the bottom of the tank. This sample is not in accordance with the manual sampling standards as described in ASTM D 4057. The applicant further stated that for fuel oil storage tanks of less than 159 cubic meters, spot sampling recommendations in ASTM D 4057-95 (2000) include a single sample from the middle (a distance of one-half of the depth of liquid below the liquid's surface). The 280-gallon fire pump day tanks are 1.06 cubic meters, so the spot sampling recommendations in ASTM D 4057 are applicable. Although the actual sample location for tanks is lower than prescribed by the ASTM D 4057 standard, the sample results are more likely to capture contaminants, water, and sediment, thus making this a conservative sample location for fuel oil containments. Additionally, the applicant stated that the diesel generator is run on a weekly basis (taking suction from the bottom of the tank) and significant stratification is unlikely in such a small tank that is mixed weekly. The staff reviewed this exception and found it acceptable because the sample location is lower, and thus more conservative, than that described in the ASTM standard, and because the generator is run weekly, which reduces the potential for significant stratification.

Exception 2. LRA Section B.2.1.20 states exceptions to the "scope of the program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. The GALL Report AMP recommends periodic sampling, draining, cleaning, and internal inspection of tanks to reduce the potential for loss of material by exposure to fuel oil contaminated with water and microbiological organisms. The applicant stated that multilevel sampling, tank bottom draining, cleaning, and internal inspection of the 550-gallon diesel fuel oil day tanks (1A-T-404, 1B-T-404, 1C-T-404, and 1D-T-404) is not periodically performed. Instead, the applicant stated that fuel oil from the 550-gallon day tanks is recirculated back to the 26,500-gallon storage tanks quarterly. To confirm the absence of any significant aging effects, the applicant will perform a one-time inspection of each of the 550-gallon day tanks and the condition will be entered into the corrective action program for resolution. The staff reviewed this exception and found it acceptable because: (1) the fuel oil contained within the tanks is analyzed prior to being placed in the tanks, (2) the fuel oil in the tanks is regularly replaced with fuel oil from a tank that is regularly analyzed for water and indications of microbiological growth, and (3) the applicant will verify the absence of any significant aging effects with a one-time inspection.

<u>Exception 3</u>. LRA Section B.2.1.20 states exceptions to the “scope of the program,” “preventive actions,” “parameters monitored or inspected,” “monitoring and trending,” and “acceptance criteria” program elements. The GALL Report AMP recommends the additions of biocides, stabilizers, and corrosion inhibitors to prevent degradation of the fuel oil quality. The Fuel Oil Chemistry Program does not require the addition of biocides, stabilizers, and corrosion inhibitors, but instead requires their use only in response to test results that indicate biocides, stabilizers, and corrosion inhibitors are needed. The staff reviewed this exception and found it acceptable because the Fuel Oil Chemistry Program includes analysis of new fuel oil prior to the addition to the fuel oil storage tanks, and analysis of existing fuel oil for particulate, water, and indications of biological growth. Additionally, the fuel oil tanks are drained of water and sediment during the regular fuel oil sample draws (in preparation for analysis), and the Fuel Oil Chemistry Program procedures require the addition of biocides, stabilizers, and corrosion inhibitors if testing results indicate their presence.

<u>Enhancement 1</u>. LRA Section B.2.1.20 states enhancements to the “scope of the program,” “preventive actions,” “parameters monitored or inspected,” and “detection of aging effects” program elements. These enhancements provide equivalent requirements for fuel oil purity and fuel oil testing, as described by the Standard TSs. The staff compared these enhancements to the appropriate program elements in GALL AMP XI.M30, and because the enhancements are consistent with the program elements in GALL AMP XI.M30, the staff finds them acceptable.

<u>Enhancement 2</u>. LRA Section B.2.1.20 states enhancements to the “scope of the program,” “preventive actions,” “parameters monitored or inspected,” and “corrective actions” program elements. The applicant stated that prior to the period of extended operation, the procedures will be enhanced to require the addition of biocides, stabilizers, and inhibitors if sampling or inspection activities detect biological activity, biological breakdown of the fuel, or corrosion products. The applicant further stated that the analysis for particulate contamination will be in accordance with modified ASTM D2276-00, Method A and analysis using this method is sufficient for the detection of corrosion products at an early stage. The staff compared these enhancements to the appropriate program elements in GALL AMP XI.M30 and finds them acceptable for providing adequate assurance that aging effects will be managed during the period of extended operation.

<u>Enhancement 3</u>. LRA Section B.2.1.20 states an enhancement to the “scope of the program,” “preventive actions,” “parameters monitored or inspected,” and “detection of aging effects” program elements. The applicant stated that prior to the period of extended operation, an internal inspection of the diesel fire pump fuel oil 280-gallon tank (T-565) using visual inspections and ultrasonic thickness examination of the tank bottom will be performed. The staff compared these enhancements to the appropriate program elements in GALL AMP XI.M30, and because the enhancements are consistent with the program elements in GALL AMP XI.M30, the staff finds them acceptable.

<u>Enhancement 4</u>. LRA Section B.2.1.20 states an enhancement to the “scope of the program,” “preventive actions,” “parameters monitored or inspected,” and “detection of aging effects” program elements. The applicant stated that prior to the period of extended operation, the procedures will be enhanced to provide quarterly water and sediment multilevel sampling on the diesel fuel oil storage tanks in accordance with ASTM D2709. During the audit, the staff questioned the applicant about an unclear testing requirement in a proposed procedure that was being developed as part of Enhancement 4.

By letter dated June 14, 2010, the staff issued RAI 3.0.3.2.10-01 which stated there was insufficient detail in the proposed procedure to provide reasonable assurance that the procedure would allow for effective detection of water in the fuel oil system.

In its response dated July 12, 2010, the applicant responded by stating that the Fuel Oil Chemistry Program includes existing procedures for sampling new fuel oil deliveries and stored fuel oil, and that these procedures require analysis of the sampled fuel oil for the presence of water and sediment by a qualified laboratory in accordance with ASTM Standard D2709, which is consistent with GALL AMP XI.M30. The applicant further stated that the unclear testing requirement in the proposed procedure would be removed and the wording from the existing Fuel Oil Chemistry Program procedure would be retained. The staff compared these enhancements to the appropriate program elements in GALL AMP XI.M30, and because the enhancements are consistent with the program elements in GALL AMP XI.M30, the staff finds them acceptable.

Enhancement 5. LRA Section B.2.1.20 states an enhancement to the “scope of the program,” “preventive actions,” “parameters monitored or inspected,” and “detection of aging effects” program elements. The applicant stated that prior to the period of extended operation, the procedures will be enhanced to provide for internal inspection of the diesel fuel oil storage tanks using visual inspections and ultrasonic thickness examination of the tank bottoms. The staff compared these enhancements to the appropriate program elements in GALL AMP XI.M30, and because the enhancements are consistent with the program elements in GALL AMP XI.M30, the staff finds them acceptable.

Enhancement 6. LRA Section B.2.1.20 states an enhancement to the “scope of the program,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements. The applicant stated that prior to the period of extended operation, the procedures will be enhanced to provide quarterly particulate sampling of the diesel fire pump fuel oil 280-gallon tank (T-565) in accordance with modified ASTM D2276-00, Method A. The modification consists of using a filter with a pore size of 3.0 microns instead of 0.8 microns. The staff compared these enhancements to the appropriate program elements in GALL AMP XI.M30, and because the enhancements are consistent with the program elements in GALL AMP XI.M30, the staff finds them acceptable.

Enhancement 7. LRA Section B.2.1.20 states an enhancement to the “scope of the program,” “parameters monitored or inspected,” and “detection of aging effects” program elements. The applicant stated that prior to the period of extended operation, the procedures will be enhanced to provide a one-time inspection of each of the 550-gallon diesel fuel oil day tanks, to verify the absence of any significant aging effects. The staff compared these enhancements to the appropriate program elements in GALL AMP XI.M30, and because the enhancements are consistent with the program elements in GALL AMP XI.M30, the staff finds them acceptable.

Based on its audit and review of the applicant’s response to RAI 3.0.3.2.10-01, the staff finds that elements one through six of the applicant’s Fuel Oil Chemistry Program, with acceptable exceptions and enhancements, are consistent with the corresponding program elements of GALL AMP XI.M30 and are, therefore, acceptable.

Operating Experience. LRA Section B.2.1.20 summarizes operating experience related to the Fuel Oil Chemistry Program. The applicant stated that its operating experience has shown that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling are being adequately managed. The applicant also provided the following operational experience:

(1) On November 5, 2003, during routine sampling of the diesel fuel oil tank (1G-T-403), sediment was observed in the purge volume prior to obtaining the fuel oil sample from the bottom drain valve. After performing the proper flushes, a sample was obtained and sent to an offsite laboratory for analysis. Additionally, 8-gallons were purged from the sample line, thus removing any remaining sediment from the bottom of the tank. After further investigation it was determined that there was a discrepancy in the two sampling techniques used during the routine task (bottom sample and a sample bomb, which is taken 6–12 inches from the tank bottom). Typically, the bottom drain sample is placed in a glass bottle (to accommodate visual inspection) and the sample bomb is typically transferred to a poly bottle. In the case of the samples taken on November 5, 2003, the bottles used were reversed from those typically used. As a result, along with inadequate labeling of the sample point, the wrong analysis was performed on the samples. The sample drawn using the sample bomb (the one in the glass bottle) was visually inspected and there was no water or sediment observed. The sample drawn from the bottom drain (the one in the poly bottle) was being analyzed for particulate amount. This analysis result was likely to be unsatisfactory because the particulates settle at the bottom of the tank. This is why regular particulate sampling is done via the bomb method and not from the bottom of the tank. Additional samples were drawn on November 6, 2003, and were analyzed. For the bottom drain sample, no sediment and no water was observed. For the bomb sample, analysis results were less than 0.01 milligrams per liter (mg/L), which is well below the 10 mg/L specification. The sampling procedure was enhanced to specify the type of bottle used and the expectations on sample labeling. This operating experience provides objective evidence that the Fuel Oil Chemistry Program identifies unsatisfactory results through routine sampling of the fuel oil tanks and provides timely investigation and resolution of the issue. Additionally, the Fuel Oil Chemistry Program initiates corrective actions to prevent reoccurrence of the similar events.

(2) On February 4, 2004, it was identified that the particulate concentration of the 1HT-403 diesel fuel oil tank increased from less than 0.01 mg/L to 3.86 mg/L. The sample that showed the increase to 3.86 mg/L was taken on January 30, 2004. The previous sample of less than 0.01 mg/L was taken on November 6, 2003. Sample results were verified with duplicate testing. However, further investigation revealed that the samples taken on January 30, 2004, were processed incorrectly. This was due to a bad sampling technique. The procedure was then analyzed, and the chemistry department decided to add a pre-job brief prior to the sampling evolutions to enhance the quality of the testing. New samples were taken and particulate concentration was found to be less than 0.01 mg/L. This operating experience provides objective evidence that the fuel oil chemistry sampling activities identify abnormal test results due to improper techniques or procedures and puts barriers in place to prevent reoccurrence in the future.

(3) In September 2004, an inspection and cleaning of the diesel fire pump fuel oil tank (T-565) identified that the inside of the tank was corroded and the liner was degraded. The diesel fire pump fuel oil tank was drained, steam cleaned, and inspected. The inspection showed minor internal surface rust and scaling at some joints, but it was not excessive. The minor rust and scaling would in no way affect the structural integrity of the tank. The apparent cause of the rust was water in the bottom of the tank. Preventive maintenance activities were put into place to drain water and sediment from

the bottom of the tank to prevent reoccurrence. This provides objective evidence that periodic inspection of the tanks identifies degradation prior to the loss of intended function. In addition, this example illustrates the implementation of corrective actions in order to prevent degraded conditions from occurring in the future.

During the audit, the staff reviewed operating experience information in the application to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. The staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.20 provides the UFSAR supplement for the Fuel Oil Chemistry Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.3-2. The staff also notes that the applicant committed (Commitment No. 20) to enhance the Fuel Oil Chemistry Program and perform one-time inspections, prior to entering the period of extended operation.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Fuel Oil Chemistry Program, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and finds that the AMP, with the exceptions, is adequate to manage the aging effects for which the LRA credits it. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 20, prior to the period of extended operation, would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.11 Reactor Vessel Surveillance

Summary of Technical Information in the Application. LRA Section B.2.1.21 describes the existing Reactor Vessel Surveillance Program as consistent, with enhancements, with GALL AMP XI.M31, "Reactor Vessel Surveillance."

The applicant stated that its program manages the loss of fracture toughness due to neutron irradiation embrittlement of the reactor vessel beltline materials. The applicant also stated that its program meets the requirements of 10 CFR 50, Appendix H. The applicant stated further that its program evaluates neutron embrittlement by projecting USE for reactor materials and impact on adjusted reference temperature (ART) for the development of P-T limit curves.

The applicant stated that embrittlement evaluations are performed in accordance with RG 1.99, Revision 2 and its program is also part of the BWRVIP ISP described in BWRVIP-86-A and BWRVIP-116, and approved by the staff. The applicant stated that the schedule for removing surveillance capsules is in accordance with the timetable specified in BWRVIP-86-A for the current operating term and in accordance with BWRVIP-116 for the period of extended operation.

The applicant stated the program monitors plant operating conditions to ensure appropriate steps are taken if reactor vessel exposure conditions are altered, such as the review and updating of 60-year fluence projections to support USE calculations and P-T limit curves. The applicant also stated that its program includes condition monitoring by removal and analysis of surveillance capsules as part of the BWRVIP ISP.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M31. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M31.

The applicant described its program for monitoring irradiation embrittlement of the RPV through testing that monitors the properties of the beltline materials. LRA Section B.2.1.21 states that the Reactor Vessel Surveillance Program will follow the requirements of the BWRVIP ISP and will apply the ISP data to the HCGS unit.

10 CFR Part 50, Appendix H requires that an ISP, which is used as a basis for a facility's reactor vessel surveillance program, be reviewed and approved by the staff. The staff noted that the ISP to be used by the applicant is a program that was developed by the BWRVIP, and the applicant will apply the BWRVIP ISP as the method by which HCGS will comply with the requirements of 10 CFR Part 50, Appendix H.

The applicant has implemented the BWRVIP ISP based on the BWRVIP-86-A report. The staff noted that this report is consistent with GALL AMP XI.M31 for the period of its current license. The staff concluded that the BWRVIP ISP in BWRVIP-86-A is acceptable for BWR licensee implementation provided that all participating licensees use one or more compatible neutron fluence methodologies. The staff's acceptance of the BWRVIP ISP for the current license period at HCGS is documented in the staff's SER dated July 23, 2004, which is addressed in License Amendment 151.

In addition, the BWRVIP developed an updated version of the ISP in the BWRVIP-116 report, which provides guidelines for an ISP to monitor neutron irradiation embrittlement of the RPV beltline materials for all U.S. BWR power plants for the period of extended operation. The BWRVIP ISP identifies capsules that must be tested to monitor neutron radiation embrittlement for all licensees participating in the ISP and identifies capsules that are available on a "contingency" basis (deferred capsules). However, the staff noted that no guidance is provided in the BWRVIP-116 for continued use, storage, or testing of deferred capsules. Table 3-3 of the BWRVIP-116 report indicates that HCGS has two capsules in the reactor that are scheduled to be removed and tested, one before and one after the beginning of the period of extended operation.

The applicant stated in its Reactor Vessel Surveillance Program and LRA Section A.2.1.21 that the Reactor Vessel Surveillance Program is part of the ISP described in BWRVIP-86-A and BWRVIP-116 and it will follow the requirements of the BWRVIP ISP and all of the conditions described in the SE, dated February 24, 2006.

The staff also reviewed the portions of the "detection of aging effects," "acceptance criteria," "confirmation process," and "administrative controls" program elements associated with the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.21 states an enhancement to the "acceptance criteria" and "confirmation process" program elements of GALL AMP XI.M31 as follows:

> Hope Creek will implement the requirements of BWRVIP-116, "BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal," including the conditions specified by the NRC in its Safety Evaluation dated February 24, 2006.

Based on its review, the staff finds this enhancement acceptable because the applicant is implementing BWRVIP-116, which is a program approved by the staff in its SE dated February 24, 2006, which adequately addresses the requirements of 10 CFR Part 50, Appendix H for BWR licensees through the end of the facility's proposed 60-year operating license.

Enhancement 2. LRA Section B.2.1.21 states an enhancement to the "detection of aging effects" and "administrative controls" program elements of GALL AMP XI.M31 as follows:

> If future plant operations exceed the limitations specified in RG 1.99, the impact of plant operation changes on the extent of reactor vessel embrittlement will be evaluated and the NRC will be notified. Similarly, if future plant operation exceeds the bounds established by surveillance data that are to determine Upper Shelf Energy or P-T limits, then the impact of plant operation changes on the extent of reactor vessel embrittlement will be evaluated and the NRC will be notified. Additionally, if all the surveillance capsules are removed, then operating restrictions will be established to ensure that the plant is operated within the conditions to which the surveillance capsules were exposed. If the reactor vessel exposure conditions (neutron flux, spectrum, irradiation temperature, etc.) are altered, then the basis for the projection to 60 years is reviewed; and, if deemed appropriate, a revised fluence projection is prepared and the effects of the revised fluence analysis on neutron embrittlement calculations will be evaluated. If necessary an active surveillance program will be reinstituted for Hope Creek.

> The employment of additional surveillance specimens will be coordinated through the BWRVIP Integrated Surveillance Program (ISP). Any changes to the reactor vessel exposure conditions and the potential need to re-institute a vessel surveillance program will be discussed with the NRC staff prior to changing the plant's licensing basis.

The staff reviewed the "detection of aging effects" and "administrative controls" program elements of GALL AMP XI.M31. Based on its review, the staff finds this enhancement acceptable because when enhanced, the applicant's program will be consistent with the recommendations of the "detection of aging effects" and "administrative controls" program elements of GALL AMP XI.M31, and the program, when enhanced, meets the criteria for an acceptable reactor vessel surveillance program as recommended in GALL AMP XI.M31.

On the basis of its review, the staff finds the applicant has demonstrated that the effects of aging due to loss of fracture toughness of the RPV beltline region will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, in accordance with 10 CFR 54.21(a)(3).

Based on its audit, the staff finds that elements one through six of the applicant's Reactor Vessel Surveillance Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.M31 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.21 summarizes operating experience related to the Reactor Vessel Surveillance Program. LRA Section B.2.1.21 contains two examples of relevant operating experience. The staff noted that the first capsule at HCGS was removed in 1994 and tested prior to the implementation of the ISP. The staff further noted that the analysis of the results indicated that the capsule received an average fast neutron fluence (E > 1.0 MeV) that was equivalent to a 32 EFPY fluence at the inner wall of the vessel, and the projected Charpy USE and ART for 32 EFPY were more than adequate to continue safe operation.

The staff noted that in 2004, the plant was granted an EPU, which resulted in an increase in the projected neutron fluence value for the limiting beltline materials at the end of the 40-year life of the plant. The applicant reanalyzed the USE and ART calculations in RG 1.99, Revision 2 to confirm that the projected toughness of the vessel remained at acceptable levels for the remainder of the current license period. The staff noted that the results were used to generate new P-T limits for normal operations of the plant. The staff confirmed the updated analyses with independent calculations.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.21 provides the UFSAR supplement for the Reactor Vessel Surveillance Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also notes that the applicant committed (Commitment No. 21) to enhance the Reactor Vessel Surveillance Program prior to entering the period of extended operation. Specifically, the applicant committed to the actions as described above in Enhancements 1 and 2. The staff reviewed the applicant's proposed UFSAR supplement and Commitment No. 21 and determined that the applicant is in accordance with 10 CFR Part 50, Appendix H.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Reactor Vessel Surveillance Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 21 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.12 Buried Piping Inspection

Summary of Technical Information in the Application. LRA Section B.2.1.24 as supplemented by letters dated September 1, 2010, and October 29, 2010, describes the existing Buried Piping Inspection Program as consistent, with an enhancement, with GALL AMP XI.M34, "Buried Piping and Tanks Inspection." The applicant stated that the program provides aging management of carbon steel, ductile cast iron, and gray cast iron buried piping susceptible to general corrosion, pitting, crevice corrosion, and microbiologically-influenced corrosion. The applicant also stated that the program relies on the visual inspection of excavated piping, including the associated coatings and wrappings. The applicant further stated that there are no in–scope buried tanks.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M34. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M34.

The staff also reviewed the portions of the "detection of aging effects" program element associated with an enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows:

Enhancement. LRA Section B.2.1.24 states an enhancement to the "detection of aging effects" program element. The applicant stated that the program will be enhanced to include at least one inspection each of carbon steel, gray cast iron, and ductile iron piping within the period of 10 years prior to the beginning of the period of extended operation. The applicant also stated that the enhancement specifies that access to each buried piping to be inspected will be conducted as part of either an opportunistic or a focused excavation and inspection. The applicant further stated that the enhancement specifies that a minimum of one additional inspection will be conducted for each material type within the first 10 years of the period of extended operation.

On the basis of its review, the staff finds this enhancement acceptable because, when it is implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL AMP XI.M34.

Based on its audit, the staff finds that elements one through six of the applicant's Buried Piping Inspection Program, with acceptable enhancements are consistent with the corresponding program elements of GALL AMP XI.M34 and, therefore, acceptable. The staff notes that even though the applicant has demonstrated consistency with each of the program elements in GALL AMP XI.M34, based on recent industry operating experience, the staff needed further information related to cathodic protection, coatings, and backfill quality in the vicinity of buried piping. The staff issued RAIs B.2.1.24 and B.2.1.24-02 and their evaluations are documented in the "operating experience" program element.

The applicant subsequently revised its enhancement in its response dated October 29, 2010, to RAI B.2.1.24-02. The revised enhancement states:

> At least one opportunistic or focused excavation and inspection will be performed on each of the material groupings, which include carbon steel, ductile cast iron, and gray cast iron piping and components during each ten year period, beginning ten years prior to entry in the period of extended operation. A second opportunistic or focused excavation and inspection on a carbon steel piping segment, which is not cathodically protected, will be performed on the service water system during each ten year period, beginning ten years prior to entry into the period of extended operation. A different segment will be inspected in each ten year period.

The staff finds this enhancement acceptable because the applicant has demonstrated consistency with each of the program elements in GALL AMP XI.M34 and based its enhancement on recent industry operating experience

<u>Operating Experience</u>. LRA Section B.2.1.24 summarizes operating experience related to the Buried Piping Inspection Program. The applicant stated that risk ranking methods were used to identify locations where susceptibility to corrosion could be anticipated, specifically citing planned inspections for the carbon steel service water piping. The applicant also stated that opportunistic inspections were performed during excavations for piping repairs, and no significant age–related deficiencies were documented.

Given that there have been a number of recent industry events involving leakage from buried or underground piping, the staff needs further information to evaluate the impact that these recent industry events might have on the applicant's Buried Piping and Tanks Inspection Program. By letter dated August 6, 2010, the staff issued RAI B.2.1.24 requesting that the applicant provide information regarding how the applicant will incorporate the recent industry operating experience into its aging management reviews and programs.

In its response dated September 1, 2010, the applicant stated that there have been no leaks of buried in-scope piping as a result of external piping corrosion, and inspections of coatings that have occurred during opportunistic inspections of ductile cast iron fire protection piping have also found the coatings to be in acceptable condition. The applicant also stated that it has risk ranked all buried piping in accordance with NACE and EPRI guidelines and the NEI Industry Initiative on Buried Piping. Based on these risk rankings, inspections of the coating and external surfaces of the pipe were conducted. The applicant further stated that portions of the in-scope steel fire protection system are cathodically protected; the rectifiers for the cathodic protection system are monitored on a semi-monthly basis and inspected and tested on an annual basis; and for the past 5 years, cathodic protection availability has exceeded 90 percent. The applicant stated that when conducting visual inspection, it will conduct excavated visual inspections of at least 8 linear feet, when practical, of buried piping. The applicant commited to at least one opportunistic or focused excavation and inspection to be performed on each of the material groupings, which include carbon steel, galvanized steel, ductile cast iron, and gray cast iron piping and components during each 10-year period, beginning 10 years prior to entry in the period of extended operation.

By letter dated October 12, 2010, the staff issued follow-up RAI B.2.1.24-02 requesting that the applicant: (a) define what is meant by excavating 8 feet of pipe when practical, state what alternative means will be utilized to determine the condition of the buried pipe and its coatings, or justify why inspecting less than 8 feet is sufficient to provide a reasonable assurance of the condition of the pipe and coatings; (b) clarify what portions of buried steel piping are protected by cathodic protection; if some portions of steel piping are not protected by a cathodic protection system, justify the scope of planned inspections; (c) clarify the periodicity of NACE potential surveys and if not conducted on an annual basis, provide justification; and (d) provide details on the quality of backfill in the vicinity of in-scope buried pipes. This was considered to be open item OI 3.0.3.2.12-1 during the issuance of the SER with open items.

In its response dated October 29, 2010, the applicant stated that, in reviewing candidate inspection sites, the applicant had determined that there is no need to have the phrase “when practical” in relation to examining 8 feet of pipe and the RAI response was subsequently revised accordingly to retract the word “when practical.” Therefore, the applicant concluded that there is no need to provide alternative inspection details for less than 8-foot inspections.

Also, the applicant stated that portions of the fire protection system are not cathodically protected. The applicant identified an error in its LRA and stated that there is no galvanized steel fire protection piping exposed to an external soil environment; LRA Table 3.3.2-10 was revised accordingly. The applicant further stated that it has also revised the LRA to inspect a buried carbon steel pipe segment in the non-cathodically protected portion of fire protection system in place of the stated inspection of buried galvanized steel piping. The applicant noted that HCGS contains only two systems (service water and fire protection) within the scope of license renewal that contains buried carbon steel piping that are not cathodically protected.

Furthermore, the applicant identified an error in the LRA and stated that the condensate storage and transfer system has no steel pipe sleeves within the scope of license renewal; LRA Table 3.4.2-1 was revised accordingly.

Additionally, the applicant stated that the service water system has four 36-inch diameter steel piping spools that provide a transition from the reinforced concrete pipe to steel piping where the service system headers penetrate the service water intake structure and reactor building. The total length of these four piping spools is 12 feet and the piping spools are not cathodically protected. The applicant stated that it will inspect two of the four piping spools during the October 2010 refueling outage and one different piping spool of the four piping spools in each 10-year period starting 10 years prior to the period of extended operation. Specifically, the applicant committed to perform an opportunistic or focused excavation and inspection on a carbon steel piping segment, which is not cathodically protected, on the service water system during each 10-year period, beginning 10 years prior to entry into the period of extended operation. A different segment will be inspected in each 10-year period. The applicant later informed the staff (ADAMS Accession No. ML110540526) that during the October 2010 outage, two of the four service water system segments, located at the service water intake structure and the reactor building, were inspected. The applicant found that both pipes were coated and the coating was in good to excellent condition. The coatings were removed on each pipe to expose the bare metal, and the applicant found that the exposed metal surfaces of the pipes were also in excellent condition.

Also, to clarify the periodicity of NACE potential surveys, the applicant stated that annual cathodic protection system effectiveness testing is conducted in accordance with NACE SP0169-2007. The testing results are documented and trended by the cathodic protection system manager and adverse trends are entered into the corrective action program. The applicant also stated that HCGS will maintain the annual testing frequency.

Finally, the applicant stated that buried piping were backfilled during original construction in accordance with construction backfill specification. The applicant stated the construction backfill specifications as:

> Bedding material within six inches of the buried coated piping will consist of sand, or an approved well graded granular material free from stones greater than 3/8 inches in diameter, or a lean fillcrete or sandcrete. The backfill requirements for the Service Water System pre-stressed concrete pipe were difference than requirements for coated metallic pipe since coating damage is not a concern. Bedding material for this piping (within 6 inches of the pipe) was required to be lean concrete or crushed stones not greater that 1 inch diameter.

The buried pipe inspection procedures require that the condition of backfill and coatings be documented. Review of inspection records note that coatings were found in acceptable condition.

Based on its review, the staff finds the applicant's response to RAI B.2.1.24 and RAI B.2.1.24-02 acceptable because: (a) the applicant will excavate a minimum of 8 feet of pipe during each inspection; (b) current inspections have demonstrated that coatings are in acceptable condition; (c) although portions of the fire protection system are not cathodically protected, the applicant has committed to perform inspections of buried fire protection piping in each 10-year period starting 10 years prior to entry into the period of extended operation; (d) the applicant has committed to perform inspections of buried service water system piping, that are not cathodically protected, in each 10-year period starting 10 years prior to entry into the period of extended operation; (e) the applicant has committed to perform inspections of buried piping of ductile cast iron piping and gray cast iron piping in each 10-year period starting 10 years prior to entry into the period of extended operation; (f) the rectifiers for the cathodic protection system are monitored on a semi-monthly basis and inspected and tested on an annual basis; annual cathodic protection system effectiveness testing is conducted in accordance with NACE SP0169-2007; and for the past 5 years, cathodic protection availability has exceeded 90 percent; and (g) the applicant has appropriate backfill specifications, with inspections to demonstrate that coatings are in acceptable condition. The staff's concerns described in RAI B.2.1.24 and RAI B.2.1.24-02 are resolved. Open item OI 3.0.3.2.12-1 is closed.

Based on its audit, the review of the application, and review of the applicant's responses to RAIs B.2.1.24 and B.2.1.24-02, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.24 provides the UFSAR supplement for the Buried Piping Inspection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.2-2, 3.3-2, and 3.4-2.

The staff also notes that the applicant committed (Commitment No. 24) to enhance the Buried Piping Inspection Program prior to entering the period of extended operation. Specifically, the applicant committed to include:

> At least one opportunistic or focused excavation and inspection will be performed on each of the material groupings, which include carbon steel, ductile cast iron, and gray cast iron piping and components during each ten year period, beginning ten years prior to entry in the period of extended operation. A second opportunistic or focused excavation and inspection on a carbon steel piping segment, which is not cathodically protected, will be performed on the service water system during each ten year period, beginning ten years prior to entry into the period of extended operation. A different segment will be inspected in each ten year period.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Buried Piping Inspection Program, the resolution of RAI B.2.1.24 and RAI B.2.1.24-02, and closure of open item OI 3.0.3.2.12-1, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation through Commitment No. 24 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.13 Lubricating Oil Analysis

Summary of Technical Information in the Application. LRA Section B.2.1.27 describes the existing Lubricating Oil Analysis Program as consistent, with an exception, with GALL AMP XI.M39, "Lubricating Oil Analysis Program." The applicant stated that the Lubricating Oil Analysis Program provides oil condition monitoring activities to manage the loss of material and the reduction of heat transfer in piping, piping components, piping elements, heat exchangers, and tanks within the scope of license renewal exposed to a lubricating oil environment. The program includes procedures for sampling, analysis, and condition monitoring activities to identify specific wear products and contamination and determine the physical properties of lubricating oil within operating machinery.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.M39. The staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.M39, with the exception of the "parameters monitored or inspected" program element.

The staff reviewed the portions of the "parameters monitored or inspected" program element associated with the exception to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the exception follows.

Exception. LRA Section B.2.1.27 states an exception to the "parameters monitored or inspected" program element. The GALL Report AMP recommends the determination of viscosity, neutralization number, and flash point for components that do not have regular oil changes, to verify the oil is suitable for continued use. The applicant stated that the determination of flash point in lubricating oil is used to indicate the presence of highly volatile or flammable materials in a relatively nonvolatile or nonflammable material, such as found with fuel contamination in lubricating oil. The existing Lubricating Oil Analysis Program includes flash point analysis for the in-service EDG lubricating oil (the only potential application for the introduction of highly volatile or flammable materials) and for all new lubricating oil. The applicant stated further that for the remaining components within the scope of the program determination of flash point is not measured. The staff reviewed this exception and found it acceptable because the analyses proposed by the applicant address flash point for all new lube oil and for all existing lube oil that has the potential for fuel contamination, which meets the intent of the corresponding GALL Report program element.

Based on its audit, the staff finds that elements one through six of the applicant's Lubricating Oil Analysis Program, with an acceptable exception, are consistent with the corresponding program elements of GALL AMP XI.M39 and are, therefore, acceptable.

Operating Experience. LRA Section B.2.1.27 summarizes operating experience related to the Lubricating Oil Analysis Program. The applicant stated that its operating experience has shown that aging effects/mechanisms are being adequately managed and that the Lubricating Oil Analysis Program will be effective in assuring that intended functions will be maintained consistent with the CLB for the period of extended operation. The applicant also provided the following operational experience:

(1) In March 2008, a lubricating oil sample was taken from the “D” emergency diesel engine crankcase in accordance with the predictive maintenance program. The total base number (TBN) was in the Fault range for the type of oil. This was an unexpected step change from past experience. The condition was entered into the corrective action program. An additional sample was taken in April 2008 to monitor the condition of the lubricating oil and to ensure that the results of the March 2008 sample were accurate. Split samples were sent to two laboratories. Replacement of the lubricating oil was unnecessary because the TBN results from the two laboratories were consistent and within the normal range for the type of oil. Therefore, this example provides objective evidence that the Lubricating Oil Analysis Program is capable of making prudent recommendations based on sample results, performing additional sampling to monitor critical lubricating oil parameters and to verify the validity of earlier samples, and adjusting corrective actions based on all of the analytical information to ensure that intended functions are maintained.

(2) In July 2005, a lubricating oil sample was taken from the “B” primary condensate pump motor upper bearing in accordance with the predictive maintenance program. The total acid number (TAN) was just above the Alert limit. The viscosity value was normal. The condition was entered into the corrective action program. A recommendation was made to change the lubricating oil in the following refueling outage. The lubricating oil was changed and the subsequent TAN value returned to the normal range. Therefore, this example provides objective evidence that the Lubricating Oil Analysis Program is capable of sampling lubricating oils, analyzing the samples for critical lubricating oil parameters, recognizing a condition adverse to quality, and implementing corrective actions to restore the critical parameters to the normal ranges.

(3) In 2002, a lubricating oil sample was taken from the “C” RHR pump motor upper bearing assembly in accordance with the predictive maintenance program. The results indicated high moisture content. A confirmatory analysis was performed, and the result was lower moisture content but one still above the limit. The condition was entered into the corrective action program. The extent of the condition was limited to the “C” RHR pump motor. HCGS entered a TS Limited Condition Operation (LCO) 02-629 due to a degraded ECCS pump. The cause of the elevated moisture content was determined to be a degraded lube oil cooler that allowed cooling water to contaminate the lubricating oil. The motor was removed, the lube oil cooler repaired, the bearing housings cleaned, and new lubricating oil added. The moisture content returned to the normal range. The RHR pump motor was restored, and the LCO exited. Therefore, this example provides objective evidence that the Lubricating Oil Analysis Program is capable of sampling lubricating oils, analyzing the samples for critical lubricating oil parameters, recognizing a condition adverse to quality, and implementing corrective actions to restore the critical parameters to the normal ranges.

During the audit, the staff reviewed operating experience information in the application to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. The staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant’s program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.27 provides the UFSAR supplement for the Lubricating Oil Analysis Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.3-2. The staff also notes that the applicant committed (Commitment No. 27) to ongoing implementation of the existing Lubricating Oil Analysis Program for managing aging of applicable components during the period of extended operation.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Lubricating Oil Analysis Program, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the applicant's one exception and its justifications and finds that the AMP, with the exception, is adequate to manage the aging effects for which the LRA credits it. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.14 ASME Section XI, Subsection IWE

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.28 describes the existing ASME Section XI, Subsection IWE Program as consistent, with enhancements, with GALL AMP XI.S1, "ASME Section XI, Subsection IWE." In the LRA, the applicant stated that its ASME Section XI, Subsection IWE Program is a condition monitoring program that provides for inspection of primary containment components including steel containment shells and their integral attachments, containment hatches and airlocks, penetration sleeves, pressure retaining bolting, and other pressure retaining components for loss of material and fretting or lockup in an indoor air or treated water environment. The applicant also stated that the scope of this AMP is consistent with the scope identified in Subsection IWE-1000 and includes Class MC pressure retaining components and their integral attachments including wetted surfaces of submerged areas of the pressure suppression chamber and vent system, containment pressure retaining bolting, and metal containment surface areas, including welds and base metal. The applicant included 10 enhancements to its ASME Section XI, Subsection IWE Program for further assurance that Class MC components are not exposed to potentially corrosive environments. Six of these enhancements were included in the LRA, and the remaining four enhancements were added in a letter dated June 14, 2010 (ADAMS Accession No. ML101680503), in response to RAI B.2.1.28. In response to staff concerns, the applicant revised Enhancement 9 by letter dated January 19, 2011 (ADAMS Accession No. ML110210677). In response to further staff concerns regarding the current configuration of the drywell air gap drains, the applicant revised the program by letter dated May 19, 2011 (ADAMS Accession No. ML11144A016). The applicant further stated that this AMP complies with ASME Code Section XI, Subsection IWE,

2001 Edition including 2003 Addenda, for steel containment (Class MC) pressure retaining components and their integral attachments, in accordance with the provisions of 10 CFR 50.55a.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated. In addition, the applicant included 10 enhancements to its ASME Section XI, Subsection IWE Program. Six of these enhancements were included in the LRA, and the remaining four enhancements were added in a letter dated June 14, 2010, in response to RAI B.2.1.28.

Also, in response to staff concerns, the applicant revised Enhancement 9 by letter dated January 19, 2011. The applicant included in its response that through boroscope inspection of each of the four drywell air gap drains, it discovered that covers were in place in each drain line that "may limit or prevent proper drainage of the drywell air gap." As a result of this finding, the applicant indicated that it planned to futher investigate one of the drain lines to better understand the configuration in order to properly clear the four drain line openings. The applicant stated that its plan would allow it to "restore the functionality of the four air gap drains prior to flood-up of the reactor cavity during the refueling outage in Spring 2012."

Subsequently, during a May 9, 2011, telephone conference call, the applicant informed the staff that its further investigation of one of the drywell air gap drain lines indicated that the location of the blockage (where covers were installed) did not coincide with the drain line's entrance into the air gap. The applicant was unable to identify, through boroscope inspection from the air gap side, an opening that coincided with the drain line. Due to the level of radiation exposure involved in performing such inspections, the applicant was not able to perform the same investigation for the remaining three drain lines for the air gap.

The staff notes that the actual configuration from the drain line blockage to the air gap is unknown. Based on the new information provided by the applicant by telephone conference call dated May 9, 2011, the staff revised its finding and conclusion of the ASME Section XI, Subsection IWE Program. The acceptance of the program, with Enhancements 4, 6, and 8, along with items 4, 6, and 8 of Commitment No. 28, was based on having a drain path for the air gap (as stated in the LRA supplement and RAI response dated June 14, 2010). Since the drain path for the air gap does not currently exist, the staff could no longer accept the program as stated.

In response to the staff's concerns regarding the configuration of the drywell air gap drains, the applicant revised the ASME Section XI, Subsection IWE Program by letter dated May 19, 2011, which included revisions to Enhancements 4, 6, 7, 8, and 9.

In order to ensure that the drywell drains are cleared and the drywell can perform its intended function, the staff will issue a license condition to the applicant. The license condition will require the applicant to establish drainage capability from the bottom of the drywell air gap on or before June 30, 2015. The license condition also states that until drainage is established from all four drains, during each refueling outage, the applicant will perform boroscope inspections and ultrasonic thickness (UT) measurements to identify potential corrosion of the steel containment shell exterior surface. After drainage is established from all four drains, the applicant will be required to perform UT measurements during each of the three subsequent refueling outages at the same locations. The license condition also requires the applicant to submit a report to the NRC staff summarizing the results of the boroscope inspections and UT measurements and if applicable, corrective actions.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S1. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP XI.S1.

The staff also reviewed the portions of the "scope of the program," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with the revised enhancements associated with the RAI responses to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.28 states an enhancement to the "scope of the program" program element. The enhancement involves the installation of an internal moisture barrier at the junction of the concrete floor and the steel containment shell prior to the period of extended operation. The original design for HCGS did not have an internal moisture barrier at the junction of the concrete floor and drywell (steel containment shell).

The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.S1. The staff finds the enhancement acceptable because the installation of a moisture barrier will prevent ingress of water below the concrete floor and preclude the potential for future corrosion of the metal containment shell at the concrete floor junction.

Enhancement 2. LRA Section B.2.1.28 states an enhancement to the "scope of the program" program element. The enhancement involves revision of the applicant's ASME Section XI, Subsection IWE Program implementing documents to require inspection of the moisture barrier after it is installed for loss of sealing in accordance with Subsection IWE-2500.

The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.S1. The staff finds the enhancement acceptable because GALL AMP XI.S1 recommends inspection of moisture barrier in accordance with ASME Code Section XI, Subsection IWE-2500.

Enhancement 3. LRA Section B.2.1.28 states an enhancement to the "scope of the program" program element. The enhancement involves verification that the reactor cavity seal rupture drain lines are clear from blockage and that the monitoring instrumentation is functioning properly. The enhancement also states that the inspection of reactor cavity drain lines will be conducted once prior to the period of extended operation and one additional time during the first 10 years of the period of extended operation.

The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.S1. In addition, in a letter dated May 19, 2011, the applicant stated that the reactor cavity seal rupture drain lines have been verified to be clear and the associated leakage monitoring instrumentation has been tested and verified functional.

The staff noted that Enhancements 5 through 8, described below, require that when any leakage occurs during the period the reactor cavity is flooded, the reactor cavity will be monitored and investigated. These actions will identify if the reactor cavity seal rupture drain lines are clear from blockage and the monitoring instrumentation is functioning properly. Therefore, the staff finds the Enhancement 3 acceptable because the inspection of reactor cavity seal rupture drain lines, once prior to the period of extended operation and one additional time during the first 10 years of the period of extended operation, will preclude the potential for water to backup and cause drywell shell corrosion.

Enhancement 4. LRA Section B.2.1.28 states an enhancement to the "scope of the program" program element. The enhancement involves verification that the drains at the bottom of the drywell air gap are clear from blockage. The enhancement also states that inspections to verify that the drains at the bottom of the drywell air gap will be conducted once prior to the period of extended operation, and one additional time during the first 10 years of the period of extended operation.

Due to the unknown configuration of the drywell air gap, the applicant revised Enhancement 4 by letter dated May 19, 2011, to include:

> Establish drainage capability from the bottom of the drywell air gap on or before June 30, 2015. The drywell air gap will be divided into four approximately equal quadrants. Drainage consists of one drain in each quadrant for a total of four drains. Each drain will be open at the bottom of the drywell air gap and be capable of draining water from the air gap.
>
> Verify that drains at the bottom of the drywell air gap are clear from blockage once prior to the period of extended operation, and one additional time during the first ten years of the period of extended operation.

The staff finds the enhancement acceptable because drainage capability from the bottom of the drywell air gap will be established and verified on or before June 30, 2015, and inspection of the drains at the bottom of the drywell air gap for blockage, once prior to the period of extended operation and one additional time during the first 10 years of the period of extended operation, will preclude the potential for water to backup and cause steel containment shell corrosion. In addition, Enhancement 9, as decribed below, the applicant committed to perform UT measurement of the drywell, establish corrosion rate, and demonstrate that the effects of aging will be managed such that the drywell performs its intended function during the period of extended operation.

Enhancement 5. LRA Section B.2.1.28 states an enhancement to the "scope of the program" program element. The enhancement involves investigation of the source of any leakage detected by the reactor cavity seal rupture drain line instrumentation and assessment of its impact on the drywell shell.

The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.S1. The staff finds the enhancement acceptable because investigating the source of leakage detected by the reactor cavity seal rupture drain line instrumentation and accessing its impact on the drywell shell will provide the basis for initiating corrective actions to reduce or eliminate the potential for metal containment shell corrosion.

Enhancement 6. LRA Section B.2.1.28 states an enhancement to the "scope of the program" program element. The enhancement involves monitoring the drains at the bottom of the drywell air gap for leakage in the event leakage is detected by the reactor cavity seal rupture drain line instrumentation.

The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.S1 and found that the enhancement did not specify the frequency for monitoring the drains at the bottom of the drywell air gap for leakage. By letter dated Auguest 9, 2010, the applicant supplemented its LRA to revise the enhancement to state that leakage from the drains at the bottom of the drywell air gap will be monitored daily.

Due to the unknown configuration of the drywell air gap, the applicant revised Enhancement 6 by letter dated May 19, 2011, to include:

> After drainage has been established from the bottom of the air gap from all four drains, monitor the drains at the bottom of the drywell air gap daily for leakage in the event leakage is detected by the reactor cavity seal rupture drain line instrumentation.

The staff found the revised enhancement acceptable because drainage capability from the bottom of the drywell air gap will be established and verified on or before June 30, 2015, and monitoring the drains at the bottom of the drywell air gap daily for leakage, in the event leakage is detected by the reactor cavity seal rupture drain line instrumentation, will provide an indication of possible steel containment shell corrosion and the basis for initiating corrective actions that would reduce the potential for steel containment shell corrosion.

Enhancement 7. By letter dated June 14, 2010, in response to RAI B.2.1.28-1, regarding leakage from the drywell penetration sleeve J13, the applicant added Enhancement 7 to the “scope of the program” program element. The enhancement involves periodically monitoring penetration sleeve J13 for water leakage when the reactor cavity is flooded up until corrective actions are taken to prevent leakage through J13.

The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.S1 and found that the enhancement did not provide a timeline for periodic monitoring of leakage from penetration sleeve J13 and addressed this concern with the applicant in a conference call dated June 21, 2010. Therefore, by letter dated August 9, 2010, the applicant supplemented its LRA to revise the enhancement to state that leakage from the penetration J13 will be monitored daily when the reactor cavity is flooded.

The applicant included an addition to Enhancement 7 by letter dated May 19, 2011, as follows:

> Monitor penetration sleeve J13 daily for water leakage when the reactor cavity is flooded up. In addition, perform a walkdown of the torus room to detect any leakage from other drywell penetrations. These actions shall continue until corrective actions are taken to prevent leakage through J13 or through the four air gap drains.

The staff finds the revised enhancement for daily inspection of penetration J13 and walkdowns of the torus room to detect any leakage from other drywell penetrations acceptable because if the accumulation of water below J13 or in the torus room is discovered, the root cause analysis will reveal whether there are cracks in the welds of reactor cavity seal plates, refueling bellows, or in the reactor cavity drain lines. This will lead to further examination and investigation to find the source of the leakage, repair of the leak, or additional testing as per Enhancements 9 and 10 noted below to ensure that the drywell can perform its intended function.

Enhancement 8. By letter dated June 14, 2010, in response to RAI B.2.1.28-1, regarding leakage from the drywell penetration sleeve J13, the applicant added Enhancement 8 to the “scope of the program” program element. The enhancement involves periodic monitoring of the lower drywell air gap drains for water leakage when the reactor cavity is flooded up.

The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.S1 and found that the enhancement did not provide a timeline for periodic monitoring of water leakage from the lower drywell air gap drains and addressed this concern with the applicant in a conference call dated June 21, 2010. Therefore, by letter dated August 9, 2010, the applicant supplemented its LRA to revise the enhancement to state that leakage from the lower drywell air gap drains will be monitored daily when the reactor cavity is flooded.

Due to the unknown configuration of the drywell air gap, the applicant revised Enhancement 8 by letter dated May 19, 2011, to include:

> Until drainage is established from all four drains, when the reactor cavity is flooded up, perform boroscope examination of the bottom of the drywell air gap through penetrations located at elevation 93’ in four quadrants, 90 degrees apart. The personnel performing the boroscope examination shall be certified as VT-1 inspectors in accordance ASME Section XI, Subsection IWA-2300, requirements. The examiners will look for signs of water accumulation and drywell shell corrosion. Adverse conditions will be documented and addressed in the corrective action program.
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> After drainage has been established from the bottom of the air gap from all four drains, monitor the lower drywell air gap drains daily for water leakage when the reactor cavity is flooded up.

The staff finds this revised enhancement acceptable because until drainage is established from all four drains, boroscope examinations will be perfomed during each refueling outage, and the boroscope examination will verify that water accumulation and drywell shell corrosion has not occurred. After drainage has been established from the bottom of the air gap from all four drains, this enhancement will provide an indication of possible water ingress into the drywell air gap. This will lead to further examination and investigation to find the source of the leakage, repair of the leak, or additional testing as per Enhancements 9 and 10 noted below to ensure that the drywell can perform its intended function.

<u>Enhancement 9</u>. By letter dated June 14, 2010, in response to RAI B.2.1.28-1, regarding leakage from the drywell penetration sleeve J13, the applicant added Enhancement 9 to the “detection of aging effects” program element. The enhancement involves performing one-time UT thickness measurements from inside the drywell in the accessible area of the drywell shell directly below penetration sleeve J13. The applicant stated that inspection and acceptance criteria will be in accordance with IWE-2000 and IWE-3000, respectively, and that in the event significant corrosion is detected, the condition will be entered in the corrective action program for evaluation and extent of condition determination.

During the refueling outage in October 2010, the applicant observed leakage from penetration sleeve J13 and the adjacent penetration sleeve J14. As stated by the applicant, the J14 penetration sleeve is horizontally adjacent to the J13 penetration sleeve with centerlines offset by approximately 21 inches. UT thickness measurements of the drywell shell in the area below penetrations J13 and J14 indicated an area of interest with slightly lower shell thickness readings. The applicant also determined that all four drains at the bottom of the drywell, including one directly below penetrations J13 and J14, were blocked.

The staff reviewed this enhancement against the corresponding program element in GALL AMP XI.S1 and found that the one-time UT thickness measurement from inside the drywell in the accessible area of the drywell shell directly below penetration sleeve J13 and the adjacent

J14 penetration sleeve may not provide enough data points to establish a corrosion rate in the drywell. By letter dated January 3, 2011, the staff issued RAI B.2.1.28-3 requesting that the applicant provide information on establishing a corrosion rate and projected loss of drywell thickness before the period of extended operation based on a one-time UT thickness measurement.

In its response dated January 19, 2011, the applicant revised Enhancement 9 to increase the number and frequency of UT thickness measurements. Due to the unknown configuration of the drywell air gap, the applicant further revised Enhancement 9 by letter dated May 19, 2011, to include:

> Until drainage is established from all four drains, perform UT thickness measurements each refuel outage from inside the drywell in the area of the drywell shell below the J13 penetration sleeve area to determine if there is a significant corrosion rate occurring in this area due to periodic exposure to reactor cavity leakage. In addition, UT measurements shall be perfomed each refuel[ing] outage around the full 360 degree circumference of the drywell between elevations 86’-11” and 88’-0” (underside of the torus [downcomer] vent piping penetrations). Inspection and acceptance criteria will be in accordance with IWE-2000 and IWE-3000[,] respectively. The results of the UT measurements shall be used to establish a corrosion rate and demonstrate that the effects of aging will be adequately managed such that the drywell can perform its intended function until April 11, 2046. Evidence of drywell shell degradation will be documented and addressed in the corrective action program.
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> After drainage has been established from the bottom of the air gap from all four drains, UT thickness measurements will be taken each of the next three refueling outages at the same locations as those previously examined as described above. These UT thickness measurements will be compared to the results of the previous UT inspections and, if corrosion is ongoing, a corrosion rate will be determined for the drywell shell. In the event a significant corrosion rate is detected, the condition will be entered in the corrective action process for evaluation and extent of condition determination.

The staff finds the revised enhancement acceptable because UT thickness measurements of the drywell in the area of the drywell shell, directly below the J13 penetration sleeve, and around the full 360 degree circumference of the drywell between elevations 86’-11” and 88’-0” (underside of the torus downcomer vent piping penetrations), during each refueling outage, until drainage is established from all four drains, will detect any indication of steel containment shell corrosion. The boroscope examinations, as described in Enhancement 8, can also detect if standing water is trapped below penetration sleeves J13 and J14 in the drywell air gap over the long term. Similarly, increasing the number and frequency of UT thickness measurements can establish a method to determine a corrosion rate, if corrosion is ongoing. Additionally, the applicant has committed to use the inspection and acceptance criteria recommended in IWE-2000 and IWE-3000. Furthermore, the applicant has committed to perform UT thickness mearurements after drainage has been established from the bottom of the air gap from all four drains during the subsequent three refueling outages to provide further staff assurance that the drywell shell steel exterior surface is not degradated. Finally, in the event a significant corrosion rate is detected, the corrective action process will be used for evaluation and extent of condition determination. Enhancement 10 describes actions planned by the applicant to monitor, trend, and evaluate long term degradation of the drywell shell due to water leakage around penetrations J13 and J14.

Enhancement 10. By letter dated June 14, 2010, in response to RAI B.2.1.28-1, regarding leakage from the drywell penetration sleeve J13, the applicant added Enhancement 10 which states an enhancement to the “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements. The enhancement involves incorporating the following three aging management activities, as recommended in the final Interim Staff Guidance (ISG) LR-ISG-2006-01, if repairs to address the reactor cavity water leakage cannot be made prior to the period of extended operation.

The first activity involves identifying drywell surfaces requiring examination and implementing augmented inspections for the period of extended operation in accordance with IWE-1240, as identified in Table IWE-2500-1, Examination Category E-C.

The second activity involves demonstrating through the use of augmented inspections that corrosion is not occurring or that corrosion is progressing so slowly that the age-related degradation will not jeopardize the intended function of the drywell shell through the period of extended operation.

The third activity involves developing a corrosion rate that can be inferred from past UT examinations and evaluating the drywell shell using the developed corrosion rate to demonstrate that the drywell shell will have sufficient wall thickness to perform its intended function through the period of extended operation, if degradation has occurred.

The staff reviewed this enhancement against the corresponding program elements in GALL AMP XI.S1, “ASME Section XI, Subsection IWE.” The staff found the enhancement acceptable because drywell shell examinations and augmented inspections for the period of extended operation will be conducted in accordance with IWE requirements as recommend in GALL AMP XI.S1. This will include UT examination of the drywell area directly below penetration J13 after the UT inspection during October 2010 and the next three refueling outages followed by regular IWE examination during each inspection period (3 times in 10 years) until the reactor cavity water leakage from penetrations J13 and J14 is repaired. In addition, augmented inspection results will be used to verify that corrosion is not occurring or progressing at a rate that will not jeopardize the intended function of the drywell shell through the period of extended operation. Development of a corrosion rate to estimate the magnitude of drywell corrosion at the end of the period of extended operation provides a method for assuring that the drywell shell will have sufficient wall thickness to perform its intended function through the period of extended operation.

Based on its audit, resolution to the RAIs, clarifications provided during a conference call, and the applicant’s supplement to the LRA, the staff finds that elements one through six of the applicant’s ASME Section XI, Subsection IWE Program, with 10 enhancements, are consistent with the corresponding program elements of GALL AMP XI.S1 and, therefore, acceptable. Furthermore, to ensure that the drywell drains are cleared and drywell can perform its intended function, the staff will issue a license condition to the applicant. The license condition will confirm that the applicant has implemented the different enhancements, as described above, and require that the applicant submit a report to the NRC staff, after each refueling outage, summarizing the results of the UT measurements and boroscope inspections performed. The applicant shall continue to submit these reports to the NRC for three refueling outages after the air gap drains are cleared and if applicable, corrective action.

Operating Experience. LRA Section B.2.1.28 summarizes operating experience related to the applicant's ASME Section XI, Subsection IWE Program. The applicant has described examples of operating experience for the HCGS metal containment in LRA Section B.2.1.28. These discussions include ISI findings performed in accordance with ASME Code Section XI, Subsection IWE requirements.

The applicant stated in the LRA that the torus shell and interior coatings were inspected in 2004 by divers performing underwater IWE program inspections resulting in identification of coating deficiencies with general corrosion and pitting. There were 16 areas with metal loss reported to range up to 30 mils (0.030 inches). The minimum torus shell thickness in these areas is 1 inch thick. The staff noted that the degradation and loss of material thickness of the torus at 16 local areas did not exceed 10 percent of the nominal plate thickness of the torus shell. In addition, the applicant cleaned and recoated the 16 local areas in the subsequent outage to prevent further degradation. The applicant also plans to re-inspect these 16 areas during the future IWE underwater inspections.

In order to evaluate the potential impacts of these deficiencies and assess consistency of the applicant's ASME Section XI, Subsection IWE Program with GALL AMP XI.S1, the staff issued RAI B.2.1.28-2, dated May 14, 2010, requesting that the applicant provide additional details of the underwater inspections performed during 2004 including: (1) the maximum depth of degradation due to corrosion, (2) corrosion allowance thickness incorporated in the original design of the torus, (3) general condition of the coating applied to the inside surface of the torus, and (4) normal design life of the Amercoat 90 coating that was applied to the inside surface of the torus.

In its response to RAI B.2.1.28-2 (items 1 and 2), by letter dated June 14, 2010, the applicant stated that during the most recent underwater inspection of the torus and coating, 99.99 percent of the coating was found to be smooth and tightly adhered to the base metal with no significant effects. The identified coating deficiencies were primarily small localized areas of mechanical or impact damage. Other than minor general corrosion of the exposed surfaces, there was no damage to the base metal. The maximum metal loss identified at one location was 30 mils. All exposed substrate locations were subsequently repaired with epoxy coating. The applicant also stated that the original design of the torus incorporated a corrosion allowance of 125 mils (1/8 inch).

The staff reviewed the applicant's response to RAI B.2.1.28-2 (items 1and 2) and finds it acceptable because the maximum metal loss in thickness at 16 small areas of the torus is 30 mils, which is significantly less than 10 percent of the nominal thickness of the torus (100 mils) allowed by ASME Code Section XI, Subsection IWE, Article IWE-3122.3. In addition, the original design of the torus incorporated a corrosion allowance of 125 mils.

In its response to RAI B.2.1.28-2 (items 3 and 4), by letter dated June 14, 2010, the applicant stated that the Amercoat 90 coating system applied to the inside surface of the torus was observed to be in excellent condition. However, there has been random localized mechanical damage to the coating. The typical damage area is not more than ¾-inch diameter, accounting for an approximate total affected area of 151 square inches (0.0062 percent of the submerged portion of the torus shell). In addition, indications of minor general corrosion without pitting of the torus were identified during the most recent inspection in 2004. The Amercoat 90 coating system is a Service Level 1 coating and is being managed in accordance with GALL AMP XI.S8, "Protective Coating Monitoring and Maintenance Program." The applicant also stated the Amercoat 90 coating system does not have a specified normal design life, and if properly installed and maintained, will have a minimum service life of 20–25 years. The applicant further stated that with proper monitoring, maintenance, and repairs, the coating system could last through the period of extended operation.

The staff reviewed the applicant's response to RAI B.2.1.28-2 (items 3 and 4) and finds it acceptable because the applicant is managing the aging of the torus consistent with GALL AMP XI.S1. The staff notes that there have been indications of minor general corrosion without loss of base metal thickness of the torus, and random localized mechanical and impact damage of the coating in 16 small areas, which were repaired and recoated, is not likely to affect the torus structural integrity and leak tightness during the period of extended operation.

The application stated in the LRA that in 2004, rust was identified during IWE program inspections on various components inside the torus shell, including a number of penetrations and downcomer supports. The applicant also stated that the condition of the base metal was acceptable; however, the applicant recoated the inside of numberous penetrations and 32 downcomer supports to prevent further degradation. The staff finds this approach to recoat penetrations and downcomers acceptable because it will prevent further degradation of the containment pressure boundary.

In 2007 and 2009, the applicant performed UT thickness measurements of the drywell shell at various locations including near the interface of the concrete and the drywell shell. This interface was accessible because the original design of HCGS did not include a moisture barrier at this location. The as-found UT thickness measurement results were in excess of nominal thickness requirements and were considered acceptable. The applicant concluded that inspections of the shell area immediately adjacent to the floor found no indications of significant corrosion damage. In addition, the applicant enhanced its ASME Section XI, Subsection IWE Program (Enhancements 1 and 2) to include installation of a moisture barrier before the period of extended operation and to perform inspections in accordance with IWE-2500 during the period of extended operation. The staff finds this proactive approach to aging management of material loss due to corrosion acceptable because it will prevent ingress of water below the concrete floor at the drywell shell interface.

The "operating experience" program element for the applicant's ASME Section XI, Subsection IWE Program describes water leakage during the 2009 refueling outage from the seal rupture drain line penetration sleeve J13 which is located in the drywell air gap region. Because water may be trapped between the concrete and the drywell steel below the penetration sleeve J13, which is located approximately 8 feet above the drywell lower air gap drains, corrosion of the drywell steel containment is possible. By letter dated May 14, 2010, the staff issued RAI B.2.28-1 requesting that the applicant provide: (1) plans for determining the root cause for the water leak, (2) an explanation for why the water did not travel below the penetration sleeve J13 and exit from the drywell lower air gap drains located approximately 8 feet below, (3) plans to perform NDE of the drywell area below the penetration sleeve J13 to demonstrate that water is not trapped in the 2-inch annular space between the drywell and concrete shield wall, and (4) plans to quantify the effects of water leakage on the drywell including volumetric examination and a detailed engineering analysis and evaluation of the drywell.

In its response to RAI B.2.28-1 (item 1), by letter dated June 14, 2010, the applicant stated that a small amount of leakage was first observed during the 2009 refueling outage exiting from penetration J13. The applicant further stated that the leakage involved about a ¼-inch wide trickle of water exiting the penetration sleeve and forming a small puddle. The leakage stopped when the reactor cavity was drained. The applicant performed various activities prior to restart from the 2009 refueling outage and determined that the leakage is due to a small crack or cracks in either the welds of the reactor cavity seal plates, refueling bellows, or reactor cavity drain lines. Additional activities were planned and conducted during the October 2010 outage to determine the root cause. These activities included: (1) inspecting reactor cavity seal rupture drain lines for blockage monitoring leakage daily from penetration sleeve J13, drywell air gap drain lines, and reactor cavity seal rupture drain lines; (2) observing variations in water leakage and characterizing how it is affected by the water levels in the reactor cavity; and (3) performing boroscope inspections below penetration sleeve J13 for conditions that prevent water leakage from reaching the drywell lower air gap drains. In addition, the applicant performed UT examinations of the drywell shell directly below penetration J13 and evaluated the results. The results of these activities are discussed below.

In its response to RAI B.2.28-1 (item 2), by letter dated June 14, 2010, the applicant stated that the water leakage did not travel below penetration sleeve J13 due the geometrical configuration of the drywell, air gap, and penetration sleeve. The staff reviewed the applicant's detailed response to RAI B.2.28-1 (item 2) and finds the explanation provided by the applicant plausible because water leakage was not observed from penetration J37 which is located directly below penetration J13. The staff also finds that additional activities planned by the applicant during the October 2010 refueling outage to confirm the root cause and leakage flow path, including the boroscope examination of the area below the penetration J13, will provide additional information about the leakage path.

In its response to RAI B.2.28-1(item 3), the applicant stated that one-time UT thickness measurements of the drywell shell in the area below penetration sleeve J13 will be performed to demonstrate that significant loss of material due to corrosion has not occurred on the drywell shell. These measurements will provide evidence that water is not trapped in the 2-inch air gap between the drywell and concrete shield wall. The inspection and acceptance criteria will be in accordance with IWE-2000 and IWE-3000, respectively. In the event significant corrosion is detected, the condition will be entered into the applicant's corrective action program. In addition, the area will be designated for augmented examination in accordance with IWE-1240 requirements.

The staff reviewed the applicant's response to RAI B.2.28-1 (item 3) and was concerned that the applicant did not specifically address the need for periodic examination of the drywell shell area below penetration sleeve J13 in case the reactor cavity water leakage is not stopped during the October 2010 refueling outage.

By letter dated January 3, 2011, the staff issued RAI B.2.1.28-3 requesting that the applicant provide information on establishing a corrosion rate and projected loss of drywell thickness to demonstrate that significant loss of material due to corrosion has not occurred on the drywell shell before the period of extended operation based on a one-time UT thickness measurement.

In its response dated January 19, 2011, the applicant revised Enhancement 9 to increase the number and frequency of UT thickness measurements. UT thickness measurement will be taken for the next three refueling outages at the same locations as those examined in 2010. These UT thickness measurements will be compared to the results of the initial UT inspections performed during the October 2010 refueling outage and, if corrosion is ongoing, a corrosion rate will be determined for the drywell shell.

In its response to RAI B.2.28-1 (item 4), by letter dated June 14, 2010, and amended by letter dated January 19, 2011, the applicant stated that the reactor cavity leakage will be repaired, if practical, before the period of extended operation. If repairs cannot be made prior to the period of extended operation, the applicant will perform augmented inspections of the affected area of the drywell surface and demonstrate through the use of augmented inspections that corrosion is not occurring or corrosion is progressing so slowly that age-related degradation will not jeopardize the intended function of the drywell through the period of extended operation, as described above. In addition, the applicant will develop a corrosion rate based on UT thickness measurements. The applicant will use this rate to project loss of drywell thickness through the period of extended operation and evaluate the results to determine if the drywell can perform its intended function during the period of extended operation with reduced thickness.

In the October 2010 refueling outage, the applicant observed leakage from penetration sleeve J13 and an adjacent penetration sleeve J14. In addition, UT thickness measurements of the drywell shell in the area below penetrations J13 and J14 indicated an area of interest with slightly lower shell thickness readings. Furthermore, the applicant determined that all four drains at the bottom of the drywell, including one directly below penetrations J13 and J14 were blocked. Therefore, the staff issued RAI B.2.28-3 requesting that the applicant provide:

1. Plans and schedule for removing the blockage of the four drains at the bottom of the drywell or if the blockage cannot be removed, details of alternative measures such as coredrills from inside drywell or torus room to remove water that may be trapped in the annular space between the drywell shell and concrete shield wall.

2. Revision to Enhancements 9 and 10 to increase the number and frequency of UT examinations to establish a corrosion rate and projected loss of drywell thickness before the period of extended operation.

3. Plans and a schedule for examination and investigation to find the source of the leakage, and repair of the leak.

In its response to RAI B.2.28-3 (item 1) dated January 19, 2011, the applicant stated that the current plan is to initially investigate one of the drain line openings, in either the 180° or 270° azimuth drain line, in the first half of 2011 to better understand the configuration such that the four drain line openings can be properly cleared. The conditions at the bottom of the drywell air gap will also be evaluated. Containment penetrations J13 and J14 are within the 210° to 240° azimuths. To provide access for inspection, the drain line piping will be disassembled from the torus room side. The information obtained from the investigation and clearing of the first drain line opening will be used to plan and implement the restoration of the remaining three drain line openings. This plan will restore the functionality of the four air gap drains prior to flood-up of the reactor cavity during the next refueling outage in the spring of 2012. The applicant further stated that it is confident that the drains can be cleared, and there are no current plans to perform alternate measures such as coredrills. In addition, the applicant has entered the blockage of the drains in the corrective action process to evaluate and implement corrective actions to restore the functionality of the drain lines.

Subsequently, during a May 9, 2011, telephone conference call, the applicant informed the staff that its further investigation of one of the drywell air gap drain lines indicated that the location of the blockage (where covers were installed) did not coincide with the drain line’s entrance into the air gap. The staff was concerned about this new finding and requested the applicant to describe in detail the existing configuarion of the air gap blocked drains, its impact on the applicant’s plans to clear these drains by the spring of 2012, and any revisions to the enhancements and commitment 28 for the ASME Section XI, Subsection IWE Program. In response to this request, by letter dated May 19, 2011, the applicant stated:

> The drywell air gap drain line as-built configuration is not in accordance with the existing design configuration, and the non-conforming condition has been entered into the corrective action process. Field investigation of the as-built configuration performed to date has confirmed that all four of the air gap drain lines are blocked and incapable of providing a drain path for water that could potentially accumulate inside the air gap space. The air gap drain line located at azimuth 0° was investigated further by erecting a temporary platform and cutting the drain line pipe at a location near where the pipe becomes embedded in the concrete wall, allowing better access to the suspected location of the blockage. A pole was inserted into the cut drain line pipe, and it was determined that the pipe was obstructed at a point that is approximately the midpoint between the outer surface of the concrete wall in the torus room, and the inner surface of the concrete wall located inside the air gap space.
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> The as-built configuration of this drain was further investigated by lowering a boroscope into the air gap through a penetration located above the area where the entrance to the air gap drain is shown on the design drawing. The boroscope inspection did not indicate the existence of an air gap drain opening or evidence of a drain cover. The boroscope inspection was repeated by lowering the boroscope through a different penetration in the same area and again the inspection could not locate the air gap drain opening or evidence of a drain cover. There was no indication of water accumulation at the bottom of the air gap. However, an accumulation of loose debris material at the bottom of the air gap was observed. The observation of foreign material, along with the inability to locate the expected drain line openings, was entered into the corrective action process. Although some uncertainty remains regarding the as-built configuration of the air gap drain lines, there are no indications of water accumulation inside the drywell air gap space and no indications of corrosion of the containment steel shell exterior surface.
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> This new finding about the drain line blockage location has impacted the initial plans to establish clearing the four drain lines by Spring of 2012. Due to the uncertainty described above and the engineering evaluations necessary to safely clear existing drains or design and install alternate drains, PSEG Nuclear will now establish drainage capability from the bottom of the drywell air gap no later than June 30, 2015.

Based on the new information provided by the applicant, the staff could no longer accept the program as stated. The acceptance of the program with Enhancements 4, 6, and 8, along with items 4, 6, and 8 of Commitment No. 28 was based on having a drain path for the air gap (as stated in the LRA supplement and RAI response dated June 14, 2010). As described by the applicant, in its May 19, 2011, letter, the drain path for the air gap does not exist.

In response to the staff's concerns regarding the current configuration of the drywell air gap drains, the applicant revised the program by letter dated May 19, 2011, which included revisions to Enhancements 4, 6, 7, 8, and 9.

The staff reviewed the applicant's revision to the program and finds it acceptable because the applicant has plans to remove the blockage in the four air gap drains on or before

June 30, 2015. Until the blockage is removed, the applicant's corrective action process will evaluate and implement corrective actions to restore functionality of the drains. In addition, the plate under the J13 and J14 penetration area has been established as an area of interest for UT measurements each refueling outages, including UT measurements performed each refueling outage around the full 360 degree cifcumference of the drywell between elevation 86'-11" and 88'-0", until drainage from the four air gap drains is estabilished, to ensure that drywell shell integrity is maintained through the period of extended operation. These UT measurements will provide sufficient data to establish a corrosion rate. In case corrosion is found to be ongoing, the applicant will ensure that the drywell shell thickness is adequate to perform its intended function through the period of extended operation, and perform root cause analysis to determine the source of corrosion and water leakage. In the event a significant corrosion rate is detected, the condition will be entered in the corrective action process for evaluation and extent of condition determination. In addition, the applicant will perform boroscope examination of the bottom of the drywell air gap through penetrations located at elevation 93' in four quadrants, 90 degrees apart, from all four drains, until drainage is established. These boroscope examinations will verify that water accumulation and drywell shell corrosion has not occurred. In case significant corrosion is detected, the applicant will manage the drywell in accordance with the recommendations of Final ISG LR-ISG-2006-01.

The staff notes augmented UT thickness measurements were taken during the October 2010 refueling outage to determine if leakage from the reactor cavity has resulted in external corrosion of the drywell shell. Drywell thickness measurements were all above nominal plate thickness except the 1.5-inch thick plate under the J13 and J14 penetrations. This plate had UT readings below nominal plate thickness, but the average readings were well above the plate minimum allowable manufacturing tolerance. The individual and average thickness measurements on the plate under the J13 and J14 penetrations during the October 2010 outage were all above the plate thickness used in the design analysis (1.4375 inches).

The applicant also stated that it will monitor penetration sleeve J13 daily for water leakage when the reactor cavity is flooded-up. In addition, the applicant will perform a walkdown of the torus room to detect any leakage from other drywell penetrations. These actions shall continue until corrective actions are taken to prevent leakage through J13 or through the four air gap drains. The staff finds it acceptable because if accumulation of water below J13 or in the torus room is discovered, the root cause analysis will reveal whether there are cracks in the welds of reactor cavity seal plates, refueling bellows, or in the reactor cavity drain lines.

Additionally, the applicant stated that it has initiated numerous activities to investigate the source of the leakage. These activities include: (1) performing inspections to confirm prior to the spring 2012 refueling outage that reactor cavity seal drain lines are clear and monitoring instrumentation for the drains is functioning properly, (2) monitoring the J13 and J14 penetrations area when the reactor cavity is flooded, (3) obtaining water leakage data to see how it varies with water level in the reactor cavity, (4) exploring the possibility of performing NDE of the reactor cavity bellows area during the spring 2012 refueling outage and restoring functionality of the drywell air gap drains on or before June 30, 2015, and (5) performing an engineering evaluation to address post spring 2012 outage conditions. The applicant further stated that if the reactor cavity leakage cannot be repaired prior to entering the period of extended operation, then the monitoring activities and evaluations of the Final ISG LR-ISG-2006-01 will be implemented in accordance with Enhancement 10.

The staff reviewed the applicant's plans and finds it acceptable because the applicant's plans and schedule for examination and investigation to find the source of the leakage and repair of the leak are acceptable. In addition, the applicant performed approximately 350 UT thickness measurements during the October 2010 outage which determined that the minimum measured thickness of the drywell was 1.49 inches. This measurement is greater than the 1.4375 inches used for the design of the drywell. Also, the applicant plans to establish a corrosion rate based on UT measurements and perform boroscope examinations during each refueling outage, until drainage is established from the four air gap drains and subsequent UT measurements in the next three refueling outages, after drainage is established from the four air gap drains. Finally, the applicant plans to perform a new engineering evaluation in the spring of 2012 to address the post-outage conditions.

Additionally, due to the unknown configuration of the the drywell air gap drains, the staff will issue a license condition to the applicant. The license condition will require the applicant to establish drainage capability from the bottom of the drywell air gap on or before June 30, 2015. The license condition also states that until drainage is established from all four drains to identify potential corrosion of the steel containment shell exterior surface, the applicant will perform boroscope inspections and ultrasonic thickness (UT) measurements. After drainage is established from all four drains, the applicant will perform UT measurements each of the subsequent three refueling outages at the same locations. The license condition also requires the applicant to submit a report to NRC staff summarizing the results of the boroscope inspections and UT measurements and if applicable, corrective action.

Based on its audit, review of the LRA and LRA supplements, resolution to the RAIs, and establishment of a license condition, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.28, as supplemented by letter dated May 19, 2011, provides the UFSAR supplement for the ASME Section XI, Subsection IWE Program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.5-2.

The staff also notes that the applicant committed (Commitment No. 28) to enhance the ASME Section XI, Subsection IWE Program prior to entering and during the period of extended operation. Specifically, Commitment No. 28 states:

1. Install an internal moisture barrier at the junction of the drywell concrete floor and the steel drywell shell prior to the period of extended operation.

2. Require inspection of the moisture barrier for loss of sealing in accordance with IWE 2500 after it is installed.

3. Verify that the reactor cavity seal rupture drain lines are clear from blockage and that the monitoring instrumentation is functioning properly once prior to the period of extended operation, and one additional time during the first ten years of the period of extended operation.

4. Establish drainage capability from the bottom of the drywell air gap on or before June 30, 2015. The drywell air gap will be divided into four

approximately equal quadrants. Drainage consists of one drain in each quadrant for a total of four drains. Each drain will be open at the bottom of the drywell air gap and be capable of draining water from the air gap.

Verify that drains at the bottom of the drywell air gap are clear from blockage once prior to the period of extended operation, and one additional time during the first ten years of the period of extended operation.

5. Investigate the source of any leakage detected by the reactor cavity seal rupture drain line instrumentation and assess its impact on the drywell shell.

6. After drainage has been established from the bottom of the air gap from all four drains, monitor the drains at the bottom of the drywell air gap daily for leakage in the event leakage is detected by the reactor cavity seal rupture drain line instrumentation.

7. Monitor penetration sleeve J13 daily for water leakage when the reactor cavity is flooded up. In addition, perform a walkdown of the torus room to detect any leakage from other drywell penetrations. These actions shall continue until corrective actions are taken to prevent leakage through J13 or through the four air gap drains.

8. Until drainage is established from all four drains, when the reactor cavity is flooded up, perform boroscope examination of the bottom of the drywell air gap through penetrations located at elevation 93’ in four quadrants, 90 degrees apart. The personnel performing the boroscope examination shall be certified as VT-1 inspectors in accordance ASME Section XI, Subsection IWA-2300, requirements. The examiners will look for signs of water accumulation and drywell shell corrosion. Adverse conditions will be documented and addressed in the corrective action program.

   After drainage has been established from the bottom of the air gap from all four drains, monitor the lower drywell air gap drains daily for water leakage when the reactor cavity is flooded up.

9. Until drainage is established from all four drains, perform UT thickness measurements each refuel outage from inside the drywell in the area of the drywell shell below the J13 penetration sleeve area to determine if there is a significant corrosion rate occurring in this area due to periodic exposure to reactor cavity leakage. In addition, UT measurements shall be perfomed each refuel[ing] outage around the full 360 degree circumference of the drywell between elevations 86’-11” and 88’-0” (underside of the torus [downcomer] vent piping penetrations). Inspection and acceptance criteria will be in accordance with IWE-2000 and IWE-3000[,] respectively. The results of the UT measurements shall be used to establish a corrosion rate and demonstrate that the effects of aging will be adequately managed such that the drywell can perform its intended function until April 11, 2046. Evidence of drywell shell

degradation will be documented and addressed in the corrective action program.

After drainage has been established from the bottom of the air gap from all four drains, UT thickness measurements will be taken each of the next three refueling outages at the same locations as those previously examined as described above. These UT thickness measurements will be compared to the results of the previous UT inspections and, if corrosion is ongoing, a corrosion rate will be determined for the drywell shell. In the event a significant corrosion rate is detected, the condition will be entered in the corrective action process for evaluation and extent of condition determination.

10. The cause of the reactor cavity water leakage will be investigated and repaired, if practical, before [the] PEO [period of extended operation]. If repairs cannot be made prior to the PEO, the program will be enhanced to incorporate the following aging management activities, as recommended in the Final Interim Staff Guidance LR-ISG-2006-01.

    a. Identify drywell surfaces requiring examination and implement augmented inspections for the period of extended operation in accordance with IWE-1240, as identified in Table IWE-2500-1, Examination Category E-C.

    b. Demonstrate through the use of augmented inspections that corrosion is not occurring or that corrosion is progressing so slowly that the age-related degradation will not jeopardize the intended function of the drywell shell through the period of extended operation.

    c. Develop a corrosion rate that can be inferred from past UT examinations. If degradation has occurred, evaluate the drywell shell using the developed corrosion rate to demonstrate that the drywell shell will have sufficient wall thickness to perform its intended function through the period of extended operation.

Based on its review, the staff finds the UFSAR supplement for the applicant’s ASME Section XI, Subsection IWE Program acceptable because it is consistent with the corresponding program description in SRP-LR Table 3.5-2. In addition, the staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit, review of the applicant’s ASME Section XI, Subsection IWE Program, and review of the applicant’s RAI responses and LRA supplements, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the applicable enhancements and confirmed that their implementation through a license condition and Commitment No. 28 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.15 Masonry Wall Program

Summary of Technical Information in the Application. LRA Section B.2.1.31 describes the existing Masonry Wall Program as being consistent, with enhancement, with GALL AMP XI.S5, "Masonry Wall Program." The applicant's Masonry Wall Program was developed to meet the regulatory requirements of 10 CFR 50.65, (Maintenance Rule); RG 1.160; and NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The LRA states that HCGS has no safety-related masonry walls or masonry walls whose failure during a seismic event could adversely impact a safety-related function. The LRA further states that NRC IE Bulletin 80-11, "Masonry Wall Design," and IN 87-67 do not directly apply at HCGS. The LRA states that the program includes masonry walls determined to be within the scope of the Maintenance Rule and has been enhanced to include masonry walls within the scope of license renewal. Masonry walls are monitored under the Structures Monitoring Program to ensure that a loss of intended function does not occur. Monitoring frequency depends on safety significance and the condition of the structure as specified in RG 1.160. The LRA further states that the monitoring frequency of masonry walls used as fire barriers is 10 years; however, the program has been enhanced to change the 10-year frequency to 5 years to allow for early detection and evaluation of potential degradation. Provisions are included for more frequent inspections for masonry walls that are degraded to the extent that the masonry wall may not meet its design basis or the masonry wall has been degraded to the extent that if the degradation were allowed to continue uncorrected until the next normally scheduled assessment, the masonry wall may not meet its design basis. Qualified personnel visually inspect masonry walls. The LRA states that the qualified personnel are experienced engineers, qualified per Structures Monitoring Program requirements, have a B.S. degree and/or Professional Engineer license, with a minimum of 4 years experience working on building structures.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S5. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.S5.

The staff also reviewed the portions of the "scope of the program," "parameters monitored or inspected," and "detection of aging effects" associated with an enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.31 states an enhancement to the "scope of the program" program element that includes addition of the following SCs that have been determined to be within the scope of license renewal: auxiliary boiler building, fire water pump house, masonry wall fire barriers, switchyard, and turbine building.

The staff finds this enhancement acceptable because, when implemented, the applicant's Masonry Wall Program will include all masonry walls within the scope of license renewal and will be consistent with GALL AMP XI.S5 relative to including all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4.

Enhancement 2. LRA Section B.2.1.31 states an enhancement to the “parameters monitored or inspected” program element that includes the addition of an examination checklist for masonry wall inspection requirements.

The staff finds this enhancement acceptable because, when implemented, the applicant’s Masonry Wall Program will be in compliance with GALL AMP XI.S5 relative to conduction of visual inspections for cracking and loss of material, and guidance in the form of a checklist on what to look for and assessment criteria of inspection findings. This enhancement will help provide assurance that the effects of aging will be adequately managed in a timely manner.

Enhancement 3. LRA Section B.2.1.31 states an enhancement to the “detection of aging effects” program element that includes the specification of an inspection frequency of not greater than 5 years for the masonry walls.

The staff finds this enhancement acceptable because, when implemented, the applicant’s Masonry Wall Program will be conservative and compliant with GALL AMP XI.S5 inspection frequency recommendations. This enhancement will help provide assurance that the effects of aging will be adequately managed in a timely manner.

Based on its audit, the staff finds that elements one through six of the applicant’s Masonry Wall Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.S5 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.31 summarizes operating experience related to the applicant’s Masonry Wall Program. The LRA states that masonry walls that perform an intended function in accordance with 10 CFR 54.4 have been systematically identified in accordance with the scoping and screening methodology described in the LRA. Internal and external operating experiences are used to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at HCGS. The LRA states that the Masonry Wall Program shows that detection of cracks and other aging effects in masonry walls are being adequately managed. The inspection history revealed minor degradation of masonry block walls, but none that could impact their intended function. The checklist from the Structures Monitoring Program was used in 2006 for the main and power transformer masonry walls that perform a fire barrier intended function with no significant degradation identified. In 2007, cracks in a masonry wall near the turbine building that performed a fire barrier intended function were identified, evaluated, found to have no impact on the design basis, and sealed. The LRA further states that procedures used to identify and document conditions adverse to quality in accordance with the corrective action program demonstrate that the Masonry Wall Program is effectively managing the aging effects of masonry walls.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.31 provides the UFSAR supplement for the Masonry Wall Program. The staff reviewed this UFSAR supplement description and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2. The staff also notes that the applicant committed (Commitment No. 31) to enhance the Masonry Wall Program prior to entering the period of extended operation. Specifically, the applicant committed to: (1) include additional buildings and masonry walls as described in LRA Section A.2.1.31, (2) add an examination checklist for masonry wall inspection requirements, and (3) specify an inspection frequency of not greater than 5 years for masonry walls.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Masonry Wall Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 31 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.16 Structures Monitoring Program

Summary of Technical Information in the Application. LRA Section B.2.1.32 describes the existing Structures Monitoring Program as being consistent, with enhancement, with GALL AMP XI.S6, "Structures Monitoring Program." The objective of the Structures Monitoring Program is to manage aging effects of structures or structural components such that there is no loss of intended function and was developed and implemented to meet regulatory requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants;" RG 1.160 (Revision 2); and NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The LRA states that the program includes masonry walls determined to be within the scope of license renewal; however, HCGS has no safety-related masonry walls or masonry walls whose failure during a seismic event could adversely impact a safety-related function, so NRC IE Bulletin 80-11, "Masonry Wall Design," does not directly apply. The Structures Monitoring Program incorporates all elements of the Masonry Wall Program and RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants." The program also relies on plant procedures that are based on guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide," to ensure proper specification of bolting material, lubricant, and installation torque. The applicant stated that structures and structural components are periodically inspected visually by qualified personnel having a B.S. Engineering degree and/or Professional Engineer license and a minimum of 4 years working on building structures. The applicant also stated that protective coatings are not relied upon to manage the effects of aging for structures included within the scope of the AMP, so they are not addressed.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S6. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.S6, with the exception of "detection of aging effects."

While reviewing the "detection of aging effects" program element, the staff noted that the LRA addresses the underground reinforced concrete structures and structures in contact with raw water subjected to an aggressive environment. In 2008, the groundwater and raw water chemistry results indicated chloride levels up to 15,000 parts per million (ppm). These chloride levels exceed the threshold limit for chlorides (less than 500 ppm) in the GALL Report. Inspection of below-grade structures will be conducted when exposed during plant excavations done for construction or maintenance activities. The LRA states that the HCGS Structures Monitoring Program has been enhanced to require periodic sampling, testing, and analysis of groundwater chemistry for pH, chlorides, and sulfates, and assessing its impact on buried structures. The LRA also states that the service water intake structure will be monitored to provide a bounding condition and indicator of the likelihood of concrete degradation for inaccessible portions of concrete structures. During the onsite audit, the applicant was asked if it had any plans for inspections of inaccessible reinforced concrete areas prior to the period of extended operation to confirm the absence of concrete degradation. The applicant responded that it did not and that operating experience indicates that there is no evidence of corrosion appearing on the interior surfaces of the concrete structures having inaccessible exterior surfaces. Since the applicant does not have plans for inspections of inaccessible areas, and the interior of the walls may not indicate the condition of the exterior walls, it is unclear to the staff that this is an adequate approach to managing aging of inaccessible concrete structures subjected to aggressive groundwater.

By letter dated May 14, 2010, the staff issued RAI B.2.1.32-1 requesting that the applicant provide: (1) locations where groundwater test samples were/are taken relative to safety–related and important-to-safety embedded concrete walls and foundations and provide historical results (i.e., pH, chloride content, and sulfate content) including seasonal variation of results; and (2) plans for inspections in locations adjacent to embedded reinforced concrete structures, where chloride levels exceed limits in the GALL Report, or, if no inspections or coring of concrete is planned to evaluate the condition of structures (e.g., presence of steel corrosion or determination of chloride profiles), provide a basis to demonstrate that the current level of chlorides in the groundwater is not causing structural degradation of embedded walls or foundations.

By letter dated June 14, 2010, the applicant responded by providing the groundwater sampling locations, as well as the sampling results for 2008. The provided data demonstrated that the wells adequately represent the groundwater present on the site and that the pH and sulfates are within the GALL Report limits, while the chlorides are beyond the limit of 500 ppm. The applicant's response also explained that the chloride levels in the river can be as high as 11,000 ppm, well above the levels found in the groundwater. Based on this fact, the applicant explained that the service water intake structure splash zones, which are exposed to the river water, will serve as a limiting condition or "leading indicator" of potential degradation of below-grade concrete. The splash zone will be inspected on a frequency not to exceed 5 years, and any degradation determined to be due to aggressive chemical attack will be assessed for applicability to below-grade structures to determine if excavation of below-grade concrete for inspection is necessary. The applicant stated that since 2000, three inspections have been conducted of the service water intake structures and no indications of aggressive chemical attack have been recorded. The applicant further explained that this "leading indicator" approach is adequate because the river water has higher chloride levels than the groundwater, the service water intake structures were built with the same concrete mix as other safety-related structures, and the concrete cover over the reinforcing steel in the service water intake structures is the same as other safety-related structures.

The staff reviewed the applicant's response and finds it acceptable because it clearly explains why the service water intake structure concrete can be used as an indicator of possible below-grade concrete degradation. The concrete mix design used for the intake structures was the same as the rest of the plant, the concrete cover is the same as the rest of the plant structures, and the intake structures are exposed to a more aggressive environment. These characteristics make the service water intake structure an appropriate indicator of the condition of below-grade concrete. In addition, the intake structures will be inspected on a frequency not to exceed 5 years, which aligns with the GALL Report recommendations. The staff's concern in RAI B.2.1.32-1 is resolved.

The staff also reviewed the portions of the "scope of the program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the enhancements follows.

Enhancement 1. LRA Section B.2.1.32 states an enhancement to the "scope of the program" program element that includes the addition of the following SCs: auxiliary boiler building; fire water pump house; shoreline protection dike and sheet piles (RG 1.127); switchyard; turbine building; transmission towers; yard structures (foundations for fire water tanks, manholes, transformer foundations credited for SBO); masonry walls, including fire barriers; building penetrations that perform flood barrier, pressure boundary, shelter and protection intended functions; miscellaneous steel (catwalks, vents, louvers, platforms, etc.); pipe whip restraints, jet impingement, and missile shields; ice barriers, trash rack (RG 1.127); panels, racks, cabinets, and other enclosures; metal-enclosed bus; component supports (including electrical cable trays; electrical conduit; tubing; heating, ventilation, and air conditioning (HVAC) ducts; instrument racks; battery racks; and supports for piping and components that are not within the scope of ASME Section XI, Subsection IWF); and duct banks that contain safety-related cables and cables credited for SBO and anticipated transient without scram (ATWS).

The staff finds this enhancement acceptable because, when implemented, the Structures Monitoring Program will include all structures considered by the applicant to require monitoring during the period of extended operation and will be in compliance with GALL AMP XI.S6, relative to the applicant specifying the structure/aging effect combinations that are managed by its Structures Monitoring Program.

Enhancement 2. LRA Section B.2.1.32 states an enhancement to the "parameters monitored or inspected" program element that includes:

(1) Observe concrete structures for reduction in equipment anchor capacity due to local concrete degradation by visual inspections of concrete surfaces around anchors for cracking and spalling.

(2) Clarify that inspections are performed for loss of material due to corrosion and pitting of additional steel components, such as embedments, panels and enclosures, doors, siding, metal deck, and anchors.

(3) Perform a one-time inspection of the external stainless steel surfaces of the expansion bellows at the condensate storage tank dike for loss of material due to corrosion, within the 10-year period prior to the period of extended operation.

(4) Require inspection of penetration seals, structural seals, and elastomers for degradation (hardening, shrinkage, and loss of strength) that will lead to loss of sealing.

(5) Require monitoring of vibration isolators associated with component supports other than those covered by ASME Code Section XI, Subsection IWF.

(6) Add an examination checklist for masonry wall inspection requirements.

(7) Enhance parameters to be monitored for wooden components to include change in material properties and loss of material due to insect damage and moisture damage.

The staff finds this enhancement acceptable because, when implemented, the Structures Monitoring Program will be in compliance with GALL AMP XI.S6, relative to parameters monitored or inspected being commensurate with industry codes, standards, and guidelines. This enhancement will help provide assurance that aging degradation leading to loss of intended functions will be detected and the extent of degradation determined so that the degradation can be adequately managed in a timely manner.

Enhancement 3. LRA Section B.2.1.32 states an enhancement to the "detection of aging effects" program element that includes:

(1) Specify an inspection frequency of not greater than 5 years for the structures including submerged portions of the service water intake structure.

(2) Require individuals responsible for inspections and assessments for structures to have a B.S. degree and/or Professional Engineer license and a minimum of 4 years experience working on building structures.

(3) Perform periodic sampling, testing, and analysis of groundwater chemistry for pH, chlorides, and sulfates on a frequency of 5 years.

(4) Require supplemental inspections of the affected in-scope structures within 30 days following an extreme environmental or natural phenomena (large floods, significant earthquakes, hurricanes, and tornadoes).

(5) Perform a chemical analysis of ground or surface water in-leakage when there is significant in-leakage or there is reason to believe that the in-leakage may be damaging concrete elements or reinforcing steel.

The staff found this enhancement acceptable because, when implemented, the Structures Monitoring Program will be in compliance with GALL AMP XI.S6 relative to inspection methods, inspection schedule, and inspector qualifications being commensurate with industry codes, standards, and guidelines, and inclusion of industry and plant-specific operating experience. This enhancement will help provide assurance that the aging degradation will be detected and quantified before there is a loss of intended functions.

<u>*Enhancement 4*</u>. LRA Section B.2.1.32 states an enhancement to the “acceptance criteria” program element that includes additional acceptance criteria as contained in American Concrete Institute (ACI) 349.3R-96. The staff found this enhancement acceptable, because when implemented, the Structures Monitoring Program will be in compliance with GALL AMP XI.S6 relative to ACI 349.3R-96 being used to provide an acceptable basis for developing acceptance criteria for concrete structural elements, steel liners, joints, coatings, and waterproofing membranes. This enhancement will help provide assurance that the need for corrective actions will be identified before loss of intended functions.

The staff reviewed the enhancements to the program elements “scope of the program,” “parameters monitored or inspected,” “detection of aging effects,” and “acceptance criteria,” and determined that, with these enhancements, the applicant’s Structures Monitoring Program is consistent with the GALL Report.

Based on its audit and review of the applicant’s response to RAI B.2.1.32-1, the staff finds that elements one through six of the applicant’s Structures Monitoring Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP XI.S6 and, therefore, acceptable.

<u>Operating Experience</u>. LRA Section B.2.1.32 summarizes operating experience related to the Structures Monitoring Program. The LRA states that operating experience is used to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at HCGS. Operating experience screens, evaluates, and acts on operating experience documents and information to prevent or mitigate consequences of similar events. The LRA states that the Structures Monitoring Program inspection history has revealed minor degradation of structural components, but none was significant enough to impact their intended function. Deficiencies identified were evaluated and corrected. Baseline inspections of all structures within the scope of the Maintenance Rule were completed in 1997. In 2007, condition monitoring inspections of the reactor building, including the primary containment and torus, were performed and indicated satisfactory results. Some minor rust was found on the torus horizontal restraint end plates that connect to the wall, and minor rust was found on the building floor framing steel, but conditions were not found to warrant immediate repair.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During the audit, the staff discussed spent fuel leakage with the applicant. The applicant explained that minimal leakage has been detected when the pool level is increased above the normal level. The applicant further explained that, based on subsequent inspections of the area around the pool, all of the leakage is contained within the SFP drain system. Based on the minimal amount of leakage and the fact that it is contained within the drain system, the staff found this condition acceptable.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.32 provides the UFSAR supplement for the Structures Monitoring Program. The staff reviewed this UFSAR supplement section and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2.

The staff also notes that the applicant committed (Commitment No. 32) to enhance the Structures Monitoring Program prior to entering the period of extended operation. Specifically, the applicant committed to:

(1) Enhance the scope of the program to include additional SCs as described in LRA Section A.2.1.32.

(2) Observe concrete structures for a reduction in equipment anchor capacity due to local concrete degradation. This will be accomplished by visual inspection of concrete surfaces around anchors for cracking and spalling.

(3) Clarify inspection criteria for loss of material due to corrosion and pitting of additional steel components, such as embedments, panels and enclosures, doors, siding, metal deck, and anchors.

(4) Perform a one-time inspection of the external stainless steel surfaces of the expansion bellows at the condensate storage tank dike for loss of material due to corrosion, within the 10-year period prior to the period of extended operation.

(5) Require inspection of penetration seals, structural seals, and elastomers for degradation that will lead to a loss of sealing by visual inspection of the seal for hardening, shrinkage and loss of strength.

(6) Require monitoring of vibration isolators associated with component supports, other than those covered by ASME Code Section XI, Subsection IWF.

(7) Add an examination checklist for masonry wall inspection requirements.

(8) Enhance parameters monitored for wooden components to include change in material properties, loss of material due to insect damage, and moisture damage.

(9) Specify an inspection frequency of not greater than 5 years for structures, including submerged portions of the service water intake structure.

(10) Require individuals responsible for inspections and assessments for structures to have a B.S. Engineering degree and/or Professional Engineer license and a minimum of 4 years experience working on building structures.

(11) Perform periodic sampling, testing, and analysis of groundwater chemistry for pH, chlorides, and sulfates on a frequency of 5 years.

(12) Require supplemental inspections of the in-scope structures within 30 days following extreme environmental or natural phenomena (large floods, significant earthquakes, hurricanes, and tornadoes).

(13) Perform a chemical analysis of ground or surface water in-leakage when there is significant in-leakage or there is reason to believe that the in-leakage may be damaging concrete elements or reinforcing steel.

(14) Enhance implementing procedures to include additional acceptance criteria details specified in ACI 349.3R-96.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Structures Monitoring Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent, based on the resolution of the RAI as discussed above. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 32 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.17 RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"

Summary of Technical Information in the Application. LRA Section B.2.1.33 describes the existing RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program as consistent, with enhancements, with GALL AMP XI.S7, "RG 1.127,"Inspection of Water-Control Structures Associated with Nuclear Power Plants." The applicant stated RG 1.127 is implemented through the Structures Monitoring Program (10 CFR 50.65), and is based on the guidance provided in RG 1.127 and ACI 349.3R. The water control structures included within the scope of license renewal are the service water intake structure and shoreline protection and dike structures. The applicant further stated that SCs including submerged portions of the service water intake structure will include an inspection frequency of 5 years.

The applicant stated safety and performance instrumentation such as seismic instrumentation, horizontal and vertical movement instrumentation, uplift instrumentation, and other instrumentation described in RG 1.127 are not incorporated in the design of HCGS water-control structures. Thus, inspection activities related to safety and performance instrumentation are not applicable and are not specified in the implementing procedures.

The applicant further stated that conformance to RG 1.127 was part of HCGS's original design basis, and elements of the program have been incorporated in the Structures Monitoring Program.

As noted below, the applicant stated that prior to the period of extended operation, the program will be enhanced to provide reasonable assurance that water-control aging effects will be adequately managed during the period of extended operation.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP XI.S7. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP XI.S7 with the exception of the "scope of the program" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

The "scope of the program" program element in the Program Basis Document SH-PBD-AMP-XI.S7 states there are no HCGS water-control structures that are credited for flood protection. It is not clear to the staff that this statement is consistent with LRA Table 2.4-9 which indicates parts of the service water intake structure as flood barrier, therefore, by letter dated May 14, 2010, the staff issued RAI B.2.1.33-01 requesting that the applicant explain the apparent inconsistency.

In its response dated June 14, 2010, the applicant explained that the statement in the basis document was potentially misleading and is revised to state, "There are no Hope Creek water-control structures that are credited for flood protection to control flood level or prevent flooding for the site general area." The applicant further explained that the service water intake structure includes the intended function of flood barrier for the safety-related equipment within the building, but not to control site general area flooding.

The staff reviewed the applicant's response and finds it acceptable because it explains the apparent discrepancy between statements in the basis document and the LRA. The water-control structures are not credited for flood protection of the site general area; however, they are credited as a flood barrier for the safety-related equipment within the structure. The staff's concern in RAI B.2.1.33-01 is resolved.

The staff also reviewed the portions of the "scope of the program," "parameters monitored or inspected," and "detection of aging effects" program elements associated with the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.33 states an enhancement to the "scope of the program" program element. The LRA explains that shoreline protection and dike structures will be added to the scope of the program. The staff found this enhancement acceptable because when the enhancement is implemented, the RG 1.127,"Inspection of Water-Control Structures Associated with Nuclear Power Plants Program" will be consistent with the guidance in GALL AMP XI.S7 and will provide assurance that the effects of aging will be adequately managed.

Enhancement 2. LRA Section B.2.1.33 states an enhancement to the “parameters monitored or inspected” program element. The LRA explains that monitoring for wooden components will be enhanced to include change in material properties and loss of material due to insect damage and moisture damage. The staff found this enhancement acceptable because when the enhancement is implemented, the RG 1.127,”Inspection of Water-Control Structures Associated with Nuclear Power Plants Program” will be consistent with the guidance in GALL AMP XI.S7 and will provide assurance that the effects of aging will be adequately managed.

Enhancement 3. LRA Section B.2.1.33 states an enhancement to the “detection of aging effects” program element. The LRA explains that inspection requirements for submerged concrete structural components will be enhanced to require that inspections be performed by dewatering a pump bay or by a diver if the pump bay is not dewatered. The staff found this enhancement acceptable because when the enhancement is implemented, the RG 1.127,”Inspection of Water-Control Structures Associated with Nuclear Power Plants Program” will be consistent with the guidance in GALL AMP XI.S7 and will provide assurance that the effects of aging will be adequately managed.

Enhancement 4. LRA Section B.2.1.33 states an enhancement to the “detection of aging effects” program element. The LRA explains that procedures will be enhanced to specify an inspection frequency of not greater than 5 years for structures, including submerged portions of the service water intake structure. The staff found this enhancement acceptable because when the enhancement is implemented, the RG 1.127,”Inspection of Water-Control Structures Associated with Nuclear Power Plants Program” will be consistent with the guidance in GALL AMP XI.S7 and will provide assurance that the effects of aging will be adequately managed.

Enhancement 5. LRA Section B.2.1.33 states an enhancement to the “detection of aging effects” program element. The LRA explains that procedures will be enhanced to require supplemental inspections of the in-scope structures within 30 days following extreme environmental or natural phenomena (large floods, significant earthquakes, hurricanes, and tornadoes). The staff found this enhancement acceptable because when the enhancement is implemented, the RG 1.127,”Inspection of Water-Control Structures Associated with Nuclear Power Plants Program” will be consistent with the guidance in GALL AMP XI.S7 and will provide assurance that the effects of aging will be adequately managed.

Based on its audit and review of the applicant’s response to RAI B.2.1.33-01, the staff finds that elements one through six of the applicant’s RG 1.127,”Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program, with acceptable enhancements are consistent with the corresponding program elements of GALL AMP XI.S7 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.33 summarizes operating experience related to the RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants Program.” The LRA explains that in 2004, industry operating experience (OE18658) was evaluated for potential generic implication at HCGS. The operating experience subject was related to a plant’s intake structure experiencing significant concrete spalling of the floors and walls inside the structure due to chloride induced reinforcement corrosion. The interior portion of the plant’s intake structure was exposed to significant saltwater leakage from various plant components. The LRA further states that the HCGS service water intake structure can be exposed to a similar environment, therefore, there is a potential for this condition to occur. The disposition of this generic evaluation was that all site safety-related structures are subject to condition monitoring in accordance with the structures monitoring program. The LRA also discusses inspections performed on submerged concrete walls and other structural components of the “D” service water intake structure pump bay to support the station equipment preventive maintenance (PM) requirements and for the condition monitoring of structures for HCGS. For the interior submerged concrete walls and the exterior submerged walls, there was no evidence of any deficiency or degradation. There was some minimal erosion at the wall corners that was noted as acceptable by the station structural engineer. There was corrosion noted on the support plates that provide the structural attachments for the submerged portion of the service water pump and screen to the structure. The upper support plates had significant corrosion that warranted an engineering evaluation of the condition. The evaluation noted that the design basis was maintained and adequate for all design-basis events (DBEs). The LRA explains that as a result of the corrective action plan for the degradations noted from this inspection and to provide for a focused inspection of the normally submerged interior structural components of the service water pump bays, future inspections will be performed under a separate PM condition monitoring inspection task to coincide with the traveling water screen/equipment station PM task.

The staff reviewed the operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant’s program would not be effective in adequately managing aging effects during the period of extended operation.

UFSAR Supplement. LRA Section A.2.1.33 provides the UFSAR supplement for the RG 1.127,”Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.5-2. The staff also notes that the applicant committed (Commitment No. 33) to enhance the RG 1.127,”Inspection of Water-Control Structures Associated with Nuclear Power Plants Program” prior to entering the period of extended operation. Specifically, the applicant committed to: (1) adding the shoreline protection and dike structure to the scope of the program, (2) including changes in material properties and loss of material of wooden components within the parameters monitored, (3) requiring submerged structural components be inspected by dewatering a pump bay or by diver, (4) specifying an inspection frequency not greater than 5 years, and (5) requiring supplemental inspections of in-scope structures within 30 days following extreme environmental phenomena.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant’s RG 1.127,”Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation through Commitment No. 33 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.18 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B.2.1.39 describes the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as consistent, with exception, with GALL AMP XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.” The applicant stated that its program is a new one-time inspection program that manages the loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. The applicant also stated that a representative sample of cable connections within the scope of license renewal will be selected for one-time testing prior to the period of extended operation. The applicant further stated that the scope of the sampling program will consider application (medium and low voltage), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.), and that the technical basis for the sample selection will be documented. The applicant also stated that the one-time test used to confirm the absence of an aging effect with respect to electrical cable connection stressors will be a specific, proven test for detecting loose connections, such as thermography or contact resistance measurement, as appropriate for the application.

Staff Evaluation. During its audit, the staff reviewed the applicant’s claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant’s program to the corresponding elements of GALL AMP XI.E6. As discussed in the Audit Report, the staff confirmed that each element of the applicant’s program is consistent with the corresponding element of GALL AMP XI.E6, with the exception of the “scope of the program,” “parameters monitored or inspected,” “detection of aging effects,” and “monitoring and trending.”

The staff also reviewed the portions of the “scope of the program,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “corrective actions” program elements associated with the exception to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff’s evaluation of this exception follows.

Exception. LRA Section B.2.1.39 states an exception to the “scope of the program,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “corrective actions” program elements. Prior to the applicant’s submittal of the LRA, the staff was working toward the issuance of a revision to GALL AMP XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualifications Requirements,” via the ISG process. The applicant stated that the exception for this AMP is that the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is consistent with the GALL Report, as modified by the September 6, 2007, proposed revision of LR-ISG-2007-02. The ISG recommends that, prior to the period of extended operation, a one-time inspection on a representative sample basis is warranted to ensure that either aging of metallic cable connections is not occurring and/or that the existing PM program is effective such that a periodic inspection program is not required. The one-time inspection verifies that loosening and/or high resistance of cable connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation are not occurring and, therefore, periodic inspections are not required. Subsequent to the applicant's LRA, a notice of availability of the final LR-ISG-2007-02 was published in the *Federal Register* on December 23, 2009 (74 FR 68287). Therefore, the staff evaluated the AMP and LRA Sections B.2.1.39 and A.2.1.39 based on the staff's aging management guidance provided by the final LR-ISG-2007-02 and GALL AMP XI.E6.

The staff finds the exception acceptable because the identified program elements are in accordance with GALL AMP XI.E6, as modified by the final LR-ISG-2007-02, for compliance with the requirements of 10 CFR 54.21(a)(3) to demonstrate that the effects of aging for certain electrical cable connections not subject to the requirements of 10 CFR 50.49 will be adequately managed during the period of extended operation.

Based on its audit and review of LRA Section B.2.1.39, the staff finds that elements one through six of the applicant's Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, with the acceptable exception, are consistent with the corresponding program elements of GALL AMP XI.E6, as modified by the final LR-ISG-2007-02 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.39 summarizes operating experience related to the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. Although a new program, the applicant stated that plant operating experience has successfully demonstrated the identification of loose connections through the effective use of thermography. The applicant also stated that plant operating experience is in alignment with industry experience, in that electrical connections have not experienced a high degree of failures and that existing plant installation and maintenance practices are effective. The applicant further stated that operating experience provides objective evidence that thermography will detect and/or monitor loose electrical connections. The applicant concluded that thermography and the corrective action program will resolve issues prior to the loss of intended function and, therefore, there is sufficient confidence that the implementation of the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will effectively confirm the absence of aging degradation of metallic cable connections. Referencing the LRA operating experience examples, the applicant concluded that the effects of aging and aging mechanisms are being adequately managed. The applicant stated that these examples provide objective evidence that the AMP will be effective in resolving problems prior to loss of function.

The staff reviewed the operating experience in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the applicant's plant operating experience database to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. Further, the staff performed a search of operating experience for the period 2000 through November 2009. Databases were searched using various keyword searches and then reviewed by technical auditor staff. Databases searched include GLs, Bulletins, Regulatory Issue Summaries, Licensee Event Reports, Event Notifications, Inspection Findings and Inspection Reports.

During its review, it was not clear based on the applicant's operating experience discussion that the referenced LRA operating experience examples were representative, in that the search methodology and criteria are not discussed, such as databases searched, connection types, time frame, or connection stressors such as application, loading, and environment. Based on the above, the staff could not conclude that the applicant's program will be effective in adequately managing aging effects during the period of extended operation. The staff determined the need for additional clarification, which resulted in the issuance of an RAI.

By letter dated May 14, 2010, the staff issued RAI B.2.1.39-1 requesting that the applicant explain the evaluation methods and search criteria used to select the representative examples in LRA Section B.2.1.39 and the associated basis document. The applicant responded by letter dated June 14, 2010, and stated that a significant source for operating experience is found in historical plant documentation records, including maintenance work records, condition reports and corrective action evaluations, external operating experience evaluations, and engineering evaluations of regulatory correspondence such as NRC INs and GLs. The applicant also stated that operating experience for existing programs is found in system and program assessment documentation such as system/program manager notebooks, system health reports, program health reports and performance indicators, self assessments, and third party assessments. The applicant further stated that no limit was specified for historical record searches although it was preferred to use more recent examples (since 2000) with the primary focus to identify operating experience where age-related degradation was precluded, mitigated, identified during performance testing, or otherwise detected or corrected prior to loss of component intended functions. In addition, the applicant stated that operating experience that indicated an AMP or aging management activity may not be effective was also considered, including potential enhancements to improve the program or activity that demonstrated that feedback from past operating experience results in appropriate program enhancements to improve aging management effectiveness. The applicant stated that specific operating experience was selected for discussion in the LRA regarding the AMP and that these examples were peer reviewed by a license renewal project manager and the site's subject matter expert and approved by the technical lead.

With the additional information provided by the applicant's RAI response, the staff finds the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program acceptable because the applicant provided a more detailed description of the data searched, evaluation methods, and search criteria employed by the applicant in selecting the representative operating experience examples. The operating experience provided by the applicant and identified by the staff's independent database search is bounded by industry operating experience with no previously unknown aging effects identified by the staff. Based on the applicant's RAI response and the staff's independent operational experience reviews, the staff concludes that the applicant's program operating experience is consistent with SRP-LR Section A.1.2.3.10, such that there is reasonable assurance that the operating experience and conclusions provided by the applicant are representative of plant operating experience and that the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will effectively manage the effects of aging and aging mechanisms during the period of extended operation. Therefore, the staff's concern described in RAI B.2.1.39-1 is resolved.

Based on its audit, review of the LRA, and the review of the applicant's response to RAI B.2.1.39-1, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.39 provides the UFSAR supplement for the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.6-2, as modified by LR-ISG-2007-02. The staff also notes that the applicant committed (Commitment No. 39) to implement the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff determines those program elements for which the applicant claimed consistency with the GALL Report and LR-ISG-2007-02 are consistent. In addition, the staff reviewed the exception and its justification and determines that the AMP, with exception, is adequate to manage the aging effects for which the LRA credits it. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.19 Metal Fatigue of Reactor Coolant Pressure Boundary

Summary of Technical Information in the Application. LRA Section B.3.1.1 describes the existing Metal Fatigue of Reactor Coolant Pressure Boundary Program as consistent, with enhancements, with GALL AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary." In LRA Section B.3.1.1, the applicant stated the Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors and tracks the number of critical thermal and pressure transients to ensure that the CUFs for selected RCPB components remain less than 1.0 through the period of extended operation. The applicant stated the program determines the number of transients that occur and uses the software program FatiguePro® to compute CUFs for select locations. The applicant also stated the program requires the generation of fatigue monitoring reports on an annual basis. These reports include a list of transient events, cycle summary event details, CUFs, a detailed fatigue analysis report, and a cycle projection report. In addition, the applicant stated that if the fatigue usage for any location increases beyond a projected amount, based on cycle accumulation trends, or if the number of cycles approaches the limit, the corrective action program will be used to evaluate the condition and determine the remedial action to be taken.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine if the conditions observed are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL AMP X.M1. As discussed in the Audit Report, the staff confirmed that these elements are consistent with the corresponding elements of GALL AMP X.M1.

The staff also reviewed the portions of the “scope of the program,” “preventive actions,” “parameters monitored or inspected,” “monitoring and trending,” “acceptance criteria,” and “corrective actions” program elements associated with the applicant’s enhancements of the program to determine if the program will adequately manage the aging effects for which it is credited.

Enhancement 1. LRA Section B.3.1.1 describes an enhancement to the “parameters monitored or inspected” program element. The enhancement includes transients in addition to the transients described in the TSs and UFSAR. The enhancement expands the fatigue monitoring program to encompass other components requiring monitoring. The applicant will implement this enhancement, prior to the period of extended operation, as described in Commitment No. 46, LRA Appendix A, Section A.5.

Because it was not clear to the staff if the commitment was to enhance the basis document (or procedure) or to make the Metal Fatigue of Reactor Coolant Pressure Boundary Program “parameters monitored or inspected” program element consistent with GALL AMP X.M1, an RAI was issued. On June 25, 2010, the staff issued RAI B.3.1.1-1, item 1 requesting that the applicant clarify if the commitment was to enhance the basis document (or procedure) or to make the Metal Fatigue of Reactor Coolant Pressure Boundary Program “parameters monitored or inspected” program element consistent with GALL AMP X.M1.

In its response dated July 26, 2010, the applicant confirmed that Enhancement 1 is proposed to make the “parameters monitored or inspected” program element of the Metal Fatigue of Reactor Coolant Pressure Boundary Program consistent with the corresponding program element of GALL AMP X.M1. The staff noted that this program element in GALL AMP X.M1 recommends monitoring of all plant transients that cause cyclic strains, which are significant contributors to fatigue usage factor. The applicant stated that additional transients meeting this GALL Report criterion, beyond those in its Metal Fatigue of Reactor Coolant Pressure Boundary Program, have been identified and will be added to the enhanced program. The applicant described those additional transients which are listed in LRA Table 4.3.1-1 with “N” (No) under the column titled “Included in Table 3.9-1 or Table 3.9-1a of UFSAR.” The applicant further stated this program enhancement will be implemented by revising the program implementing procedures to include monitoring of the additional transients added by Enhancement 1.

Based on its review, the staff finds the applicant’s response to RAI B.3.1.1-1, item 1 acceptable because the applicant is including these additional transients to be monitored by its Metal Fatigue of Reactor Coolant Pressure Boundary Program during the period of extended operation, consistent with the GALL Report recommendation to monitor all plant transients that cause cyclic strains, which are significant contributors to fatigue usage factor and will include the monitoring of these transients in its implementing procedures of this program.

During the review, the staff noted the transients specified in TS Table 5.7.1-1 and tracked pursuant to the monitoring requirements in TS 5.7.1, are a subset of the design-basis transients listed in UFSAR Sections 3.9.1.1.1 through 3.9.1.1.11 and Tables 3.9-1 and 3.9-1a. It was not evident to the staff which process would be used at HCGS to track the design-basis transients that were listed in the UFSAR sections or tables but were not within the scope of the stated TS requirement. On June 30, 2010, the staff issued RAI B.3.1.1-1, item 2 requesting that the applicant clarify the process that will be used at HCGS to track the design-basis transients that are listed in the UFSAR but are not within the scope of TS 5.7.1.

In its response dated July 26, 2010, the applicant stated that the process that will be used to track the occurrences of those design-basis transients that are listed in the UFSAR, but are not within the scope of TS 5.7.1 will be the combination of procedures and a fatigue monitoring software program. The applicant further stated that with Enhancement 2 this process will become predominantly automated based on plant parameter monitoring using a software program to obtain plant operating data, and supplemented by input from manual cycle counting. The staff noted that existing plant procedures currently track transients listed in the TSs and these procedures will be enhanced to track the occurrences of those design-basis transients that are listed in the UFSAR but are not within the scope of TS 5.7.1. The applicant committed (Commitment No. 46) to implement Enhancements 1 and 2 prior to the period of extended operation.

Based on its review, the staff finds the applicant's response to RAI B.3.1.1-1, item 2 acceptable because the applicant is including design-basis transients that are listed in the UFSAR but are not within the scope of TS 5.7.1 to be monitored by its Metal Fatigue of Reactor Coolant Pressure Boundary Program during the period of extended operation, consistent with the GALL Report recommendation to monitor all plant transients that cause cyclic strains, which are significant contributors to fatigue usage factor and will include the monitoring of these transients in its implementing procedures of this program.

During the review, the staff noted that additional transients were incorporated into the program and included in LRA Table 4.3.1-1, "HCGS Reactor Pressure Vessel Design Transients and 60-Year Cycle Projections." These transients are the safety relief valve actuation transient, the core spray injection event transient, the HPCI event transient, the reactor water cleanup pump trip event transient, standby liquid control (SLC) injection event transient, the CRD event transient, the LPCI event transient, and the reactor recirculation single loop operation event transient. It was not evident to the staff if this list included all the additional transients. It was also not evident if the applicant was proposing the AMP track these additional transients or if the applicant was proposing to update the design basis in UFSAR Section 3.9.1.1 to include these additional transients.

On June 30, 2010, the staff issued RAI B.3.1.1-1, item 3 requesting that the applicant identify the additional transients referred to in Enhancement 1 of the AMP and to clarify which ASME Code Class 1 components these additional transients are applied to. The staff also asked the applicant to clarify whether an update of the design basis will be performed to include these transients, and if so, to identify the sections of the UFSAR affected. The applicant was also asked to clarify whether this will be covered within the scope of an LRA commitment. The staff asked the applicant to justify omitting these transients from the design basis.

In its response dated July 26, 2010, the applicant stated that the additional transients and their associated design number of cycles are derived from events reported from all UFSAR sources, as indicated in LRA Table 4.3.1-1, Note 1, and also from the applicable design-basis calculations. The applicant stated that since these additional transients are already included in the design basis, no changes to the design basis are being made and, therefore, no changes to UFSAR Section 3.9.1.1 are required as a result of the additional transients being added to the Metal Fatigue of Reactor Coolant Pressure Boundary Program. Furthermore, since no sections or tables in UFSAR Section 3.9.1.1 are changed, the applicant stated that no activities to revise UFSAR Section 3.9.1.1 are required. The applicant provided a table listing the ASME Code Class 1 Components affected by these additional transients and the corresponding LRA Table that lists the corresponding component.

Based on its review, the staff finds the applicant's response to RAI B.3.1.1-1, item 3 acceptable because the additional transients were already part of its design basis and there was not a need to update the UFSAR to include these additional transients.

During the review, the staff noted that the applicant proposed enhancing the fatigue monitoring program to expand the "program to encompass other components identified to have fatigue as an analyzed aging effect, which require monitoring." The staff noted that a similar enhancement is given in Enhancement 4 of the AMP, in the "corrective actions" program element in GALL AMP X.M1. The "corrective actions" program element recommendation in GALL AMP X.M1 states, in part, that for programs that monitor a sample of high fatigue usage locations, "corrective actions include a review of additional affected reactor coolant pressure boundary locations." It was not apparent to the staff if the expansion criteria in Enhancement 1 is applied to the "scope of the program," "monitoring and trending," or "corrective actions" program elements in the program or whether it is redundant to the enhancement discussed in Enhancement 4 of the AMP.

On June 30, 2010, the staff issued RAI B.3.1.1-1, item 4 requesting that the applicant clarify whether the expansion criterion in Enhancement 1 is being applied as an enhancement of the "monitoring and trending" program element or "corrective actions" program element of the AMP, or whether it is redundant with the enhancement discussed in Enhancement 4 of the AMP. The staff also asked the applicant to justify if the expansion aspect of the enhancement does not relate to a corrective action activity, why the expansion referred to in Enhancement 1 was not also placed in the "scope of the program" or "monitoring and trending" program elements of the AMP.

In its response dated July 26, 2010, the applicant stated that the expansion criterion in Enhancement 1 is for expansion of the number of transients and components being monitored by the program, and not for expansion of the RCPB locations to be reviewed as a result of an environmental fatigue sample location usage factor approaching its design limit in Enhancement 4; therefore, it is not redundant. The applicant also stated that Enhancement 1 does not provide enhancements to the "scope of the program" or "corrective actions" program elements, since these elements do not discuss the transients or components to be monitored by the program. The staff reviewed the corresponding program elements of GALL AMP X.M1 and finds the applicant's determination that Enhancement 1 does not affect the "scope of the program" and "corrective actions" program elements. However, Enhancement 1 can be applied to the "monitoring and trending" program element, since the expansion of components increased the number of "high fatigue usage locations" beyond those in the current fatigue monitoring program. By letter dated July 26, 2010, the applicant amended its LRA to identify that the "monitoring and trending" program element is affected by Enhancement 1. The staff reviewed the "monitoring and trending" program element of GALL AMP X.M1 which states the program monitors a sample of high fatigue usage locations. The staff noted that the applicant's Enhancement 1 expands the fatigue monitoring program to encompass other components identified to have fatigue as an analyzed aging effect, which require monitoring, consistent with the recommendations of the GALL Report.

Based on its review, the staff finds the applicant's response to RAI B.3.1.1-1, item 4 acceptable because the staff confirmed that Enhancement 1 does not affect the "scope of the program" and "corrective actions" program elements of GALL AMP X.M1, and the applicant identified that this enhancement does impact the "monitoring and trending" program element and amended its LRA to reflect this impact. The staff also finds that the applicant's Enhancement 1 is consistent with the recommendations of the "monitoring and trending" program element of GALL AMP X.M1.

Based on its review, the staff finds Enhancement 1 acceptable because it is consistent with the recommendations of the GALL Report, as described above in the staff's evaluation of RAI B.3.1.1-1.

Enhancement 2. LRA Section B.3.1.1 states an enhancement to the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements. This enhancement expands on the existing program element to use a software program to automatically count transients and calculate cumulative usage on select components. By letter dated September 20, 2010, the applicant amended its Enhancement 2 to state that, at this time, only cycle–based fatigue monitoring will be used and if stress–based fatigue monitoring is used in the future, it will consider the six stress terms in accordance with the methodology from ASME Section III, Subsection NB, Subarticle NB-3200.The applicant proposed to implement this enhancement, prior to the period of extended operation, as identified in Commitment No. 46, LRA Appendix A, Section A.5, as amended by letter dated September 20, 2010.

The staff noted that the applicant is only using cycle–based fatigue monitoring as part of its Metal Fatigue of Reactor Coolant Pressure Boundary Program. The staff further noted that this technique does not rely on software that uses a simplified input to the Greens' function of only one value of stress, which was expressed in NRC RIS 2008-30. The staff further noted that cycle–based fatigue monitoring uses the design-basis fatigue calculations which consider the six stress terms in accordance with the methodology from ASME Section III, Subsection NB, Subarticle NB- 3200 for the reactor pressure vessel components.

Based on its review, the staff finds the applicant's amendment to Enhancement 2 acceptable because: (1) the applicant does not rely on the use stress-based fatigue monitoring software that uses a simplified input to the Greens' function, which uses only one value of stress as stated in NRC RIS 2008-30, "Fatigue Analysis of Nuclear Power Plant Components" (2) the applicant relies only on cycle–based fatigue monitoring that uses the design-basis fatigue calculations which consider the six stress terms in accordance with the methodology from ASME Section III, Subsection NB, Subarticle NB- 3200 for the reactor pressure vessel components, and (3) the applicant addressed the concerns associated with NRC RIS 2008-30.

During the review, it was not evident to the staff whether the enhancement is being made to make the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements of the Metal Fatigue of Reactor Coolant Pressure Boundary Program consistent with the corresponding program elements in GALL AMP X.M1. It was also not evident to the staff what would be enhanced in the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The staff could not determine if the enhancement would involve a change to the FatiguePro® monitoring software or an alternative program, the stated program elements in the basis document or procedure for this AMP, the implementing procedure for this AMP, or some combination of these software/document bases.

On June 30, 2010, the staff issued RAI B.3.1.1-2 requesting that the applicant confirm the enhancement is being proposed to make the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements of the Metal Fatigue of Reactor Coolant Pressure Boundary Program consistent with those in GALL AMP X.M1. The staff also asked the applicant to clarify what will be enhanced and to address how the enhancement affects the program elements.

In its response dated July 26, 2010, the applicant stated that Enhancement 2 will make the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements of its program consistent with those in GALL AMP X.M1. The applicant stated the current program as described in LRA Section B.3.1.1 does not use a fatigue monitoring software program, and Enhancement 2 will cause implementation of the use of a fatigue monitoring software program, and not be limited to only an anticipated update of the software program. The applicant further stated that the implementation of the fatigue monitoring software program involves not only installation of the fatigue monitoring software program, but also implementation of new and/or revised procedures. The staff reviewed the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements of GALL AMP X.M1, which recommends the preventive measures to mitigate fatigue cracking caused by anticipated cyclic strains in the material, maintaining the cumulative usage below the design limit of 1.0, and monitoring all plant transients that cause cyclic strains, which are significant contributors to the fatigue usage factor. The staff determined that Enhancement 2 and the implementation of the fatigue monitoring software program provide the applicant a tool to mitigate fatigue cracking caused by anticipated cyclic strains in the material, maintaining the cumulative usage below the design limit of 1.0, and monitoring all plant transients that cause cyclic strains, which are significant contributors to the fatigue usage factor.

Based on its review, the staff finds the applicant's response to RAI B.3.1.1-2 acceptable because the actions associated with Enhancement 2 are consistent with the recommendations of the "scope of the program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements of GALL AMP X.M1.

Based on its review, the staff finds Enhancement 2 acceptable because it is consistent with the recommendations of the GALL Report, as described above in the staff's evaluation of RAI B.3.1.1-2.

Enhancement 3. LRA Section B.3.1.1 states an enhancement to the "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements. This enhancement addresses the effects of the reactor coolant environment on component fatigue life for a sample of critical components identified in NUREG/CR-6260. The applicant will implement this enhancement prior to the period of extended operation, as identified in Commitment No. 46, LRA Appendix A, Section A.5.

The staff reviewed this enhancement against the corresponding program elements in GALL AMP X.M1. The staff noted the applicant's enhancement appropriately expands the existing program element to address the effects of the reactor coolant environment on component fatigue life. It was not evident to the staff whether this enhancement was being proposed to make the "preventive actions," "parameters monitored or inspected," and "acceptance criteria" program elements for the Metal Fatigue of Reactor Coolant Pressure Boundary Program consistent with those in GALL AMP X.M1. The staff sought additional clarification on how this enhancement related to the acceptance criteria recommendation for environmental fatigue calculations in the "acceptance criteria" program element of GALL AMP X.M1. It was also not evident to the staff how this enhancement related to the "preventive actions" and "parameters monitored or inspected" program elements in GALL AMP X.M1.

On June 30, 2010, the staff issued RAI B.3.1.1-3 requesting that the applicant confirm the stated enhancement is being proposed to make the “preventive actions,” “parameters monitored or inspected,” “monitoring and trending,” and “acceptance criteria” program elements of the Metal Fatigue of Reactor Coolant Pressure Boundary Program consistent with that in GALL AMP X.M1. The applicant was also requested to clarify how this enhancement relates to the acceptance criteria recommendation for environmental fatigue calculations in the “acceptance criteria” program element of GALL AMP X.M1 and with the aging management recommendations in the “preventive actions” and “parameters monitored or inspected” program elements in GALL AMP X.M1.

In its response dated July 26, 2010, the applicant stated that Enhancement 3 is being proposed to make the “preventive actions,” “parameters monitored or inspected,” “monitoring and trending,” and “acceptance criteria” program elements its program consistent with that in GALL AMP X.M1. The applicant stated that Enhancement 3 provides an additional acceptance criterion to the existing Metal Fatigue Reactor Coolant Pressure Boundary Program to maintain the fatigue usage factor below the design code limit using the fatigue life correction factors developed to assess the impact of environmental fatigue. The staff reviewed the corresponding program element of GALL AMP X.M1 and noted the recommendation includes maintaining the fatigue usage below the design code limit considering environmental fatigue effects. The staff finds that the applicant’s Enhancement 3 is consistent with the recommendations to the “acceptance criteria” program element of GALL AMP X.M1. The applicant stated that Enhancement 3 relates to recommendations in the “preventive actions” program element in GALL AMP X.M1 by considering the effects of the reactor coolant environment on the component fatigue life. The staff reviewed the corresponding program element of GALL AMP X.M1 and noted the recommendation includes consideration of the effect of the reactor water environment on fatigue cracking of RCS components due to anticipated cyclic strains. The staff finds that the applicant’s Enhancement 3 is consistent with the recommendations to the “preventive actions” program element of GALL AMP X.M1. The applicant stated that Enhancement 3 relates to recommendations in the “parameters monitored or inspected” and “monitoring and trending” program elements in GALL AMP X.M1 by adding the monitoring of a sample of critical components for the plant identified in NUREG/CR-6260. The staff reviewed the corresponding program element of GALL AMP X.M1 and noted the recommendation includes monitoring transients that cause significant fatigue usage, a sample of critical RCPB components is to be monitored, and the sample includes locations identified in NUREG/CR-6260, as a minimum. The staff finds that the applicant’s Enhancement 3 is consistent with the recommendations to the “parameters monitored or inspected” and “monitoring and trending” program elements of GALL AMP X.M1.

Based on its review, the staff finds the applicant’s response to RAI B.3.1.1-3 acceptable because the applicant described in detail how Enhancement 3 is consistent with the recommendations from the corresponding program elements of GALL AMP X.M1, and the staff confirmed that Enhancement 3 is consistent with the GALL Report.

Based on its review, the staff finds Enhancement 3 acceptable because it is consistent with the recommendations of the GALL Report, as described above in the staff’s evaluation of RAI B.3.1.1-3.

Enhancement 4. LRA Section B.3.1.1 states an enhancement to the “corrective actions” program element. This enhancement to the existing program element addresses the expanded review of RCPB locations if the usage factor for one of the environmental fatigue sample locations approaches its design limit.

During the review, it was not evident to the staff whether the stated enhancement was being made to make the “corrective actions” program element of the Metal Fatigue of Reactor Coolant Pressure Boundary Program consistent with the corresponding program element in GALL AMP X.M1. It was also not evident to the staff exactly what is being enhanced relative to the information that has been submitted for the Metal Fatigue of Reactor Coolant Pressure Boundary Program and specifically, whether the enhancement would involve an enhancement of the “basis document or procedure” for this AMP or the implementing procedure for this AMP, or both.

On June 30, 2010, the staff issued RAI B.3.1.1-4 requesting that the applicant confirm the stated enhancement is being proposed to make the “corrective actions” program element of the Metal Fatigue of Reactor Coolant Pressure Boundary Program consistent with that in GALL AMP X.M1. The applicant was also requested to clarify what will be enhanced (e.g., basis document, implementing procedure, etc.) relative to Enhancement 4 of the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

In its response to RAI B.3.1.1-4 dated July 26, 2010, the applicant stated that Enhancement 4 is being proposed to make the “corrective actions” program element of its program consistent with that in GALL AMP X.M1. The applicant further stated that the implementing procedures will be revised to include the review of additional RCPB locations, if the usage factor for one of the environmental fatigue sample locations approaches its design limit, but will not involve updating the basis document. The staff reviewed the “corrective actions” program element of GALL AMP X.M1, which states that for programs that monitor a sample of high fatigue usage locations, corrective actions include a review of additional affected RCPB. The staff finds the applicant’s proposed Enhancement 4 consistent with the recommendations of the corresponding program element of GALL AMP X.M1.

Based on its review, the staff finds the applicant’s response to RAI B.3.1.1-4 acceptable because the applicant’s proposed Enhancement 4 includes a sample expansion of additional RCPB locations if the usage factor for one of the environmental fatigue sample locations approaches its design limit as part of its corrective actions, consistent with the recommendations of the GALL Report.

Based on its review, the staff finds Enhancement 4 acceptable because it is consistent with the recommendations of the GALL Report, as described above in the staff’s evaluation of RAI B.3.1.1-4

Based on its audit and review of the applicant’s responses to RAIs B.3.1.1-1 through B.3.1.1-4, the staff finds that elements one through seven of the Metal Fatigue of Reactor Coolant Pressure Boundary Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL AMP X.M1 and, therefore, acceptable.

<u>Operating Experience</u>. LRA Section B.3.1.1 summarizes operating experience related to the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The applicant stated that the Metal Fatigue of Reactor Coolant Pressure Boundary Program is responsive to industry and plant-specific emerging issues. To support this statement, the applicant listed examples pertaining to ECCS actuation experienced in May 2007, an HPCI event experienced in October 2004, and evaluation of the 2006 annual review of plant transients that indicated the possibility of the heat-up and cool-down transient exceeding the 40-year lifetime ratio if the current trend of transients would continue.

The staff noted that, as a result of an HPCI event that occurred in October 2004, the applicant indicated that the cumulative number of HPCI event cycles would exceed the applicant's number of cycles assumed for this transient in the design basis. The staff also noted that the applicant considers this HPCI event to fall within the scope of a previously non-monitored ECCS injection event, and that the applicant's corrective action was to evaluate this event and to include ECCS HPCI transient events within the scope of the applicant's cycle counting procedure. The staff also noted that, as a result of ECCS HPCI actuation experienced in May 2007, a corrective action was invoked and the applicant updated the fatigue usage analysis for the core spray nozzle.

By letter dated June 30, 2010, the staff issued RAI 4.3-03 requesting that the applicant explain and justify why the LRA lists two different 60-year projected CUF values for the core spray nozzles. The staff also requested that the applicant identify and justify which 60-year non-environmental effects CUF value should be used for the core spray nozzles in LRA Tables 4.3.1-2 and 4.3.5-1. Furthermore, identify the assumptions that were used to reduce the CUF for the core spray nozzle by a factor of 13 in the reanalysis of the component.

In its response dated July 22, 2010, the applicant stated that the CUF values for the core spray nozzle (safe end/thermal sleeve and nozzle body) in LRA Table 4.3.1-2 were inadvertently not updated to reflect the final results of the calculation revision completed during preparation of the LRA. The applicant further stated that the updated final 60-year CUF values are 0.0202 and 0.1063 for the core spray nozzle (safe end/thermal sleeve) and the core spray nozzle (nozzle body), respectively. The applicant stated the design-basis 60-year CUF values presented in LRA Table 4.3.5-1 for the core spray nozzle (safe end/thermal sleeve and nozzle body) are based on the final results of the revised calculation, which is the current design analysis record. The staff noted that the values presented in LRA Table 4.3.1-2 should be consistent with those presented in LRA Table 4.3.5-1 and, therefore, LRA Table 4.3.1-2 is revised. The staff finds the applicant's revision to LRA Table 4.3.1-2 acceptable because it represents the final results of the calculation revision which represents the current design analysis record.

The applicant also stated in its response that prior to the most recent calculations performed for 60 years of operation for the core spray nozzle (safe end/thermal sleeve) in support of the LRA, the previous analyses performed to evaluate the October 2004 HPCI event used the original core spray nozzle safe end design. The applicant stated that the original safe end design used a threaded-in thermal sleeve, and the analysis applied a stress concentration factor of 5 at this location which resulted in the primary plus secondary stress intensity range significantly exceeding 3 S_m (three times the design stress intensity) and a resulting K_e (simplified elastic-plastic strain correction factor) value of 3.33. The applicant stated that this threaded location became the bounding location which was evaluated in subsequent analyses and the original analysis design-basis CUF value at the bounding location for 40 years was 0.796. The staff noted that this bounding location was evaluated in the October 2004 HPCI event using the original analysis, which resulted in a CUF value of 0.815. The staff also noted that this CUF value was calculated based on accumulated transients up to the date of the operating experience example.

The applicant clarified that the safe end was replaced prior to initial plant operation, but this configuration change was not incorporated into the previous fatigue analyses. The applicant stated the new configuration was an integral safe end without threads which was included in the finite element model and used to perform the fatigue analysis to support the LRA. The applicant also stated that the fatigue analysis performed for the LRA considered the integral safe end as fabricated of Alloy 600 instead of stainless steel, with a stainless steel thermal sleeve welded to the integral safe end, plus the addition of a new weld at the safe end to nozzle location. The staff noted that beyond the changes in safe end design and material, the fatigue analysis performed for the LRA also refined the transient parameters, as compared to the simplified transient parameters used in the original analysis. The staff further noted that these refinements included more detail with respect to time steps, nozzle and vessel temperatures and flows, and the use of actual lower flow rates associated with HPCI events when compared to flow rates shown in the thermal cycle diagram. The applicant stated that the thermal cycle diagram assumed all HPCI flow was injected through the core spray nozzle even though the system is designed to split the flow between the core spray and feedwater nozzles. The applicant also stated that the fatigue summary from the previous fatigue analyses shows that the alternating stress values for all transient load set pairs were multiplied by the K_e multiplier of 3.33, whereas only a few load set pairs in the current fatigue analysis are affected by Ke. The staff finds the reduction in CUF from the original fatigue analyses, compared to the fatigue analyses performed for the LRA, reasonable because the combination of the safe end design and material change, refinements with respect to time steps, nozzle and vessel temperatures and flows, and the use of actual lower flow rates associated with HPCI events and the application of Ke to the affected load set pairs would result in removal of some conservatism that was assumed in the original analysis. The staff noted that with regard to the nozzle body location, the original design-basis 40-year CUF was 0.071 and it did not experience a similar significant reduction in resultant calculated fatigue usage.

Based on its review, the staff finds the applicant’s response to RAI 4.3-03 acceptable because: (1) the applicant clarified the discrepancy between LRA Tables 4.3.1-2 and 4.3.5-1, and (2) the applicant’s reduction in CUF for the core spray nozzle (safe end/thermal sleeve) was reasonable based on the collective differences between design (geometry and material) and the refinement of transient parameters, as described above.

The staff also noted that the applicant’s annual review in 2006 of past plant transient events indicated a possibility that the cumulative number of plant heat-up and cool-down transients would exceed the 40-year design-basis limit for the transients if the current trend of transients would continue. The staff noted the applicant evaluated this condition and indicated that the latest trend for these events is 3.5 heat-up transients per year and 3.5 cool-down transients per year, which is more frequent than the average trend of 3 heat-up transients per year and 3 cool-down transients per year based on a 40-year life limit of 120 transients. The staff noted that the applicant concluded that the appropriate corrective action for its 2006 annual transient review was to continue monitoring the plant’s heat-up and cool-down transients in accordance with the cycle counting requirements of the program.

To assess the appropriateness of this corrective action, the staff assessed the cumulative number of heat-up and cool-down cycles accumulated at the plant to date. The staff noted that, as of December 2007, the total number of heat-up cycles and cool-down cycles was 79, and that according to the TSs, each of these transients had a limiting design basis allowable of 120. The staff noted that in LRA Section 4.3, the applicant is dispositioning the CUF values for the ASME Code Class 1 components in accordance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(iii) and will manage the impact of fatigue-induced cracking on the intended functions of these components in accordance with the cycle counting and periodic CUF update provisions of this AMP. The staff also observed that the applicant still has a significant margin on cycle counting for the transients.

Thus, based on this review, the staff concludes that the applicant has taken an acceptable corrective action and the program will be capable of managing the impact of fatigue-induced cracking on the intended functions of the plant's ASME Code Class 1 components using this program because: (1) the applicant is using the program to disposition the CUF-based TLAAs for these components in accordance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(iii); (2) the applicant's program includes both cycle counting provisions and provisions to perform periodic updates of the CUF values for these components, which is consistent with the staff's recommendations in the "parameters monitored or inspected" and "detection of aging effects" program elements in GALL AMP X.M1; and (3) there remains sufficient margin on cycle counts for the plant's heat-up and cool-down transients at this time.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.3.1.1 provides the UFSAR supplement for the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 4.3-2. The staff also notes that the applicant committed (Commitment No. 46), as amended by letter dated September 20, 2010, to enhance the Metal Fatigue of Reactor Coolant Pressure Boundary Program prior to entering the period of extended operation. Specifically, the applicant committed to: (1) include additional transients beyond those defined in the TSs and the UFSAR, and expanding the fatigue monitoring program to encompass other components identified to have fatigue as an analyzed aging effect, which require monitoring; (2) use a software program to automatically count transients and calculate cumulative usage on select components, using cycle–based fatigue monitoring and if stress–based fatigue monitoring is used in the future, it will consider the six stress terms in accordance with the methodology from ASME Section III, Subsection NB, Subarticle NB-3200; (3) address the effects of the reactor coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components for the plant identified in NUREG/CR-6260; and (4) require a review of additional reactor coolant pressure boundary locations if the usage factor for one of the environmental fatigue sample locations approaches its design limit..

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 46 prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3 AMPs That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Appendix B, the applicant identified the following AMPs that were not consistent with or not addressed by the GALL Report:

- High Voltage Insulators
- Periodic Inspection
- Aboveground Non-Steel Tanks
- Buried Non-Steel Piping Inspection
- Boral Monitoring Program
- Small-Bore Class 1 Piping Inspection

For the AMPs that are not consistent with or not addressed by the GALL Report, the staff performed a complete review of the AMPs to determine whether they were adequate to monitor or manage aging. The staff's review of these plant-specific AMPs is documented in the following section of this SER.

3.0.3.3.1 High Voltage Insulators

Summary of Technical Information in the Application. LRA Section B.2.2.1 describes the new High Voltage Insulators Program as plant-specific. The applicant stated that the High Voltage Insulators Program is a new condition monitoring program that manages the degradation of insulator quality at HCGS due to the presence of salt deposits or surface contamination. The scope of the program includes high-voltage insulators in the 500-kV switchyard, portions of the 13.8-kV buses, and the 500-kV Salem-HCGS crosstie. The applicant also stated that High Voltage Insulators Program includes visual inspections to detect unacceptable indications of insulator surface contamination. The visual inspections will be performed on a twice per year frequency and will be effective in detecting the applicable aging effects, and the frequency of monitoring is adequate to prevent significant degradation. The applicant also stated that this program will be implemented prior to the period of extended operation so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation.

Staff Evaluation. The staff reviewed program elements one through six of the applicant's program against the acceptance criteria for the corresponding elements as stated in SRP-LR Section A.1.2.3. The staff's review focused on how the applicant's program manages aging effects through the effective incorporation of these program elements. The staff's evaluation of each of these elements follows.

Scope of the Program. LRA Section B.2.2.1 states that the High Voltage Insulators Program is a new program that manages the aging effect of degradation of insulator quality. The scope of the program includes insulators in the 500-kV switchyard ring bus, portions of the 13.8-kV buses, and the 500-kV Salem-HCGS crosstie. The high-voltage insulators are those credited for supplying power to in-scope components for recovery of offsite power following an SBO.

The staff reviewed the applicant's "scope of the program" program element against the criteria in SRP-LR Section A.1.2.3.1, which states that the scope of the program should include the specific SCs of which the program manages aging. The staff determined that the specific commodity groups for which the program manages aging effects are identified (insulators in the 500-kV switchyard ring bus, portions of the 13.8-kV buses, and the 500-kV Salem-HCGS crosstie for recovery of offsite power following an SBO), which satisfies the criterion defined in SRP-LR Appendix A.1.2.3.1.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1 and, therefore, the staff finds it acceptable.

Preventive Actions. LRA Section B.2.2.1 states that the High Voltage Insulators Program is not a preventive or mitigation program. The High Voltage Insulators Program is a condition monitoring program that relies upon visual inspections of insulator surfaces in order to manage the degradation of insulator quality due to the presence of salt deposits or surface contamination.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which states that condition monitoring programs do not rely on preventive actions and thus, preventive actions need not be provided. The staff notes that this is a condition monitoring program and that there is no need for preventive actions, consistent with SRP-LR Section A.1.2.3.2.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2 and, therefore, the staff finds it acceptable.

Parameters Monitored or Inspected. LRA Section B.2.2.1 states that walkdowns are periodically conducted to visually inspect material conditions in the switchyards. Inspections of high-voltage insulators will be performed visually to determine a threshold for implementing corrective actions. These inspections will detect the presence and extent of any aging degradation due to the presence of salt deposits. The applicant also stated that porcelain insulators typically have a shiny surface; if the surface is dull, then contamination is present. Typically, heavy contamination will be apparent by the buildup at the base area of a vertical insulator. Similarly, for insulators in the dead-end horizontal configuration, significant drip marks are an indication that the location should be monitored. The applicant further stated that the most important area that signifies heavy contamination is when contamination is observed on the inside ridges on the underside of the porcelain bells. Evidence of salt deposits or surface contamination will be monitored and inspected to ensure high-voltage insulator intended function during the period of extended operation.

The staff reviewed the applicant's "parameters monitored or inspected" program element against the criteria in SRP-LR Section A.1.2.3.3, which states that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular structure and component intended function(s). The parameter monitored or inspected should detect the presence and extent of aging effects.

The staff noted that salt deposits and surface contamination are the potential aging effects for high-voltage insulators and a buildup of contamination could enable the conductor voltage to track along the surface and can lead to insulator flashover. The staff determined that visual inspection is acceptable for detecting and managing the aging effects of salt deposits or surface contamination associated with high-voltage insulators and will ensure the component intended function during the period of extended operation.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3 and, therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.2.2.1 states that system walkdowns in the switchyards are conducted periodically, and include a visual inspection of high-voltage insulator surface conditions in accordance with system engineering walkdown procedures. These walkdowns will continue into the period of extended operation, and will detect any aging degradation due to the presence of salt deposits or surface contamination. These inspections will be performed visually to determine a threshold for implementing corrective actions.

The applicant stated that high-voltage insulators within the scope of this program are to be visually inspected at least twice per year. This is an adequate period to detect aging effects before a loss of component intended function since experience has shown that aging degradation is a slow process. The applicant also stated that a twice per year inspection interval will provide multiple data points during a 20-year period, which can be used to characterize the degradation rate. The buildup of surface contamination is typically a slow, gradual process that is even slower for rural areas with generally less suspended particles and contaminant concentrations in the air than urban areas. HCGS is located in a rural area, not near heavy industry that would provide a source for contaminants. The applicant further stated that there has only been one event associated with insulator contamination, which was not age-related or time-dependent. Therefore, operating history and plant location support a twice per year inspection frequency, which in turn provides reasonable assurance that the aging effect of degraded insulator quality will be detected prior to failure and loss of intended function.

The staff reviewed the applicant's "detection of aging effects" program element against the criteria in SRP-LR Section A.1.2.3.4, which states that the parameters to be monitored or inspected should be appropriate to ensure that the SC intended function(s) will be adequately maintained for license renewal under all CLB design conditions. This includes aspects such as method or technique (e.g., visual, volumetric, surface inspection), frequency, and timing of inspection to ensure timely detection of aging effects. In addition, it states that the method or technique and frequency may be linked to plant-specific or industry-wide operating experience.

The staff noted that the buildup of surface contamination is a slow, gradual process and HCGS is located in a rural area, not near heavy industry that would provide a source of contamination. There has been one event associated with insulator contamination. The plant-specific operating experience supports a twice per year inspection frequency. The staff determined that visual inspection is an acceptable technique for inspecting surface contamination of insulators and a twice per year inspection frequency is adequate to ensure timely detection of aging effects.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4 and, therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.2.2.1 states that monitoring activities will be prescribed by procedures that contain consistent qualitative criteria for insulator surface contamination levels (e.g., slight, moderate, and heavy), and results will be documented providing a predictable extent of degradation. Visual techniques and a twice per year frequency are appropriate for monitoring high-voltage insulators and have been employed with success by transmission and distribution organizations. The applicant also stated that qualitative criteria for insulator surface contamination levels (e.g., slight, moderate, and heavy), will allow a predictable extent and rate of surface contamination degradation. The results will be trended, from inspection to inspection, providing a basis for timely corrective actions such as insulator cleaning/washing, prior to a loss of insulator intended function.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Section A.1.2.3.5, which states that monitoring and trending activities should be described, and they should provide predictability of the extent of degradation and thus effect timely corrective or mitigative actions. This program element describes how the data collected are evaluated and may also include trending for a forward look. The parameter or indicator trended should be described.

The staff determined that trending for insulator surface contamination levels (slight, moderate, and heavy) will be documented and will provide a predictable extent of degradation. The result will be trended from inspection to inspection and will provide a basis for timely corrective actions prior to a loss of intended functions.

The staff confirmed that the "monitoring and trending" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.5 and, therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.2.2.1 states visual inspection of high-voltage insulators will be prescribed by procedures that contain consistent qualitative criteria for insulator surface contamination levels (e.g., slight, moderate, and heavy), and the results will be documented providing a predictable extent of degradation. Inspection findings are to be within the acceptance criteria of these procedures, to ensure that high-voltage insulator intended function is maintained under all CLB design conditions during the period of extended operation.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which states that the acceptance criteria of the program and its basis should be described. The acceptance criteria, against which the need for corrective actions will be evaluated, should ensure that the SC intended function(s) are maintained under all CLB design conditions during the period of extended operation.

The staff determined that the applicant described acceptance criteria for insulator surface contamination level (e.g., slight, moderate, or heavy) in the plant procedures. Inspection findings are to be within the acceptance criteria of these procedures to ensure that high-voltage insulator intended function is maintained during the period of extended operation. The staff confirmed that the "acceptance criteria" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.6 and, therefore, the staff finds it acceptable.

Operating Experience. LRA Section B.2.2.1 summarizes operating experience related to the high-voltage insulators. The applicant stated that industry operating experience illustrates the potential for loss of insulator quality due to salt deposits and surface contamination on switchyard insulators. The applicant also stated that demonstrating the new High Voltage Insulator Program will be effective is achieved through objective evidence that shows the aging effect of degradation of insulation quality caused by the presence of salt deposits and surface contamination is being adequately managed. The applicant further stated that the following examples of operating experience provide objective evidence that the new High Voltage Insulators Program will be effective in assuring that the intended function will be maintained consistent with the CLB for the period of extended operation:

(1) In March 1993, Crystal River Unit 3 experienced a loss of the 230-kV switchyard (normal offsite power to safety-related buses) when a light rain caused arcing across salt-laden 230-kV insulators and opened switchyard breakers. In March 1993, the Brunswick Steam Electric Plant Unit 2 switchyard experienced a flashover of some high-voltage insulators attributed to a winter storm. Since 1982, Pilgrim Nuclear Power Station experienced several losses of offsite power when ocean storms deposited salt on the 345-kV switchyards, causing the insulator to arc to ground. The applicant further stated that in response to this industry experience, existing 6-month inspections of HCGS 13-kV insulators were expanded to include the 500-kV insulators for salt contamination. The switchyard was inspected using thermography and corona detection equipment in the winter and summer of 2002, and no significant contamination buildup was found. The response and actions associated with this industry experience were revisited in 2003 following the effects of Hurricane Isabel. Switchyard insulator inspections were instituted along with contingency planning for an insulator cleaning strategy. The applicant further stated that steps for initiating inspection of switchyard insulator surfaces were added to severe weather abnormal operating procedures upon forecast of severe weather. This example provides objective evidence that industry operating experience will be applied toward this new program, and corrective actions will be taken when the quality of insulator surfaces is threatened by storms and contamination.

(2) One plant-specific event occurred at HCGS on September 18–19, 2003, when Hurricane Isabel passed a considerable distance to the south and west of the site. Strong winds with gusts in excess of 60 miles per hour (mph) caused switchyard insulators to become coated with salt. The rain had stopped prior to the strongest winds, leaving the salt spray to dry on switchyard insulators. HCGS operated throughout the storm. The combination of salt on the insulator surface and atmospheric moisture subsequently caused a flashover. Another insulator flashover occurred shortly thereafter with no effect on plant operation. In response to the switchyard faults, HCGS was manually taken offline on September 20th. The high-voltage insulators were subsequently cleaned/washed prior to returning the units to operation. The applicant further stated that this event demonstrates that corrective actions are taken when high-voltage insulator degradation is found and, because this is the only high-voltage insulator-related event of record, flashover due to salt contamination of insulators at HCGS is considered rare.

(3) Visual inspection of HCGS switchyard high-voltage insulators is performed twice per year for evidence of salt and contamination. These inspections have been in place since 1996 and have not found or observed degraded insulator quality other than “slight” surface contamination, even during periods of excessively dry weather, which would warrant cleaning or other corrective measures. This component history demonstrates that minor contamination is washed away by rainfall or snow, and cumulative buildup has not been experienced and is not expected to occur (with the exception of infrequent storms like Hurricane Isabel). Visual inspection results for high-voltage insulators are evaluated as part of transmission and distribution outage inspections, as well as switchyard system walkdowns. This example provides objective evidence that the aging effect of degraded insulation quality is capable of being detected, and that the mechanisms of salt deposit and surface contamination on high-voltage insulators will be

managed prior to loss of intended function. The applicant further stated that the HCGS operating experience for the High Voltage Insulators Program provides sufficient confidence that the implementation of the High Voltage Insulators Program will effectively identify degradation prior to failure.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which states that operating experience with the existing program should be discussed. The operating experience should provide objective evidence to support the conclusion that the effects of aging will be adequately managed so that the SC intended function(s) will be maintained during the period of extended operation.

The staff finds that although the High Voltage Insulators Program is a new program with no operating experience for implementation, the applicant has captured insulator operating experience through reviewing industry operating experience and onsite documentation. The applicant reviewed industrial as well as plant-specific operating experience to provide the objective evidence that the new High Voltage Insulators Program will be effective in assuring that the intended function will be maintained consistent with the CLB for the period of extended operation. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program.

The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.2.1 provides the UFSAR supplement for the High Voltage Insulators Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 3.6-2.

The staff notes that the applicant committed (Commitment No. 40) to implement the new High Voltage Insulators Program prior to entering the period of extended operation.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its technical review of the applicant's High Voltage Insulators Program, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.2 Periodic Inspection

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.2.2 describes the new Periodic Inspection Program as a plant-specific program. The applicant stated that the Periodic

Inspection Program manages stainless steel, aluminum, and copper alloy components for loss of material, reduction of heat transfer, and elastomers for hardening and loss of strength. The applicant also stated that this program will manage cracking of the stainless steel standby diesel generator exhaust expansion joints. The applicant further stated that the program includes visual inspections and ultrasonic wall thickness measurements to detect loss of material.

Staff Evaluation. The staff reviewed program elements one through six of the applicant's program against the acceptance criteria for the corresponding elements as stated in SRP-LR Section A.1.2.3. The staff's review focused on how the applicant's program manages aging effects through the effective incorporation of these program elements. The staff's evaluation of each of these elements follows.

Scope of the Program. LRA Section B.2.2.2 states that the scope of the Periodic Inspection Program monitors aging effects in stainless steel, aluminum, copper alloy piping, piping components, piping elements, heat exchanger components, tanks and ducting components, and elastomers not included in other AMPs.

The staff reviewed the applicant's "scope of the program" program element against the criteria in SRP-LR Section A.1.2.3.1, which states that the scope of the program should include the specific SCs of which the program manages the aging.

The staff concluded that the scope of the Periodic Inspection Program is consistent with the corresponding element of SRP-LR Section A.1.2.3.1 because it includes specific SCs for which it will manage aging during the period of extended operation.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1 and, therefore, the staff finds it acceptable.

Preventive Actions. LRA Section B.2.2.2 states that the Periodic Inspection Program is a condition monitoring program and does not include activities for prevention or mitigation of aging effects.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which states that, for condition or performance monitoring programs, they do not rely on preventive actions and thus, this information need not be provided.

The staff concluded that the "preventive actions" program element of the Periodic Inspection Program is consistent with the corresponding element of SRP-LR Section A.1.2.3.2 because the Periodic Inspection Program is a condition monitoring program and does not need to include preventive actions.

The staff confirmed that the "preventive actions" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.2 and, therefore, the staff finds it acceptable.

Parameters Monitored or Inspected. LRA Section B.2.2.2 states that the Periodic Inspection Program will detect loss of material in stainless steel, aluminum, and copper alloys, hardening and loss of strength in elastomers, cracking of standby diesel exhaust expansion joints, and the presence and extent of fouling that could result in reduction of heat transfer of heat transfer surfaces. The applicant also stated that the program includes provisions for visual inspections and ultrasonic wall thickness measurements to detect loss of material.

The staff reviewed the applicant's "parameters monitored or inspected" program element against the criteria in SRP-LR Section A.1.2.3.3, which states that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular SC intended function(s). For a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects.

The staff concluded that the "parameters monitored or inspected" element of the Periodic Inspection Program is consistent with the corresponding element of SRP-LR Section A.1.2.3.3 because the applicant identified and linked specific degradations to particular SCs, monitoring their condition through visual or volumetric inspections assuring that they can fulfill their intended functions.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3 and, therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.2.2.2 states the Periodic Inspection Program will use visual inspections and ultrasonic wall thickness measurements to detect aging effects of components within the scope of this program prior to loss of their intended function. The applicant stated that the visual inspections will focus on: (1) loss of material in metals identified within the scope of the program; (2) cracking of standby diesel exhaust expansion joints; (3) fouling that could result in reduction of heat transfer in heat exchanger coils; (4) hardening and loss of strength in elastomers, where visual inspections may be augmented by physical manipulations. The applicant also stated that the visual inspections and ultrasonic measurements will be performed on a representative sample of components based on system operating conditions and plant operating experience and accessibility during their periodic disassembly. The applicant further stated that a 10-year inspection frequency is established based on plant and industry operating experience, which indicates that a 10-year inspection frequency will be adequate to detect loss of material prior to loss of the component's intended function.

The staff reviewed the applicant's "detection of aging effects" program element against the criteria for this element articulated in SRP-LR Section A.1.2.3.4, which states: (1) identify aging effects linked to SCs and monitor these before loss of their intended function(s); (2) monitor and inspect appropriate parameters; (3) designate inspection methods, techniques (i.e., visual, volumetric, surface inspection), their frequency, population criteria (i.e., similarity of materials of construction, fabrication, procurement, design, installation, operating environment, or aging effects), sample size (i.e., its basis and bias), data collection, and timing based on plant-specific or industry-wide operating experience; (4) maintain plant's redundancy, diversity, and defense-in-depth consistent with the CLB; (5) describe "when," "where," and "how" program data is collected.

The staff concluded that a 10-year inspection frequency is appropriately selected and established because it is based on plant-specific and industry operating experience. After further reviews and comparisons of the "detection of aging effects" program element in LRA Section B.2.2.2 with that of SRP-LR Section A.1.2.3.4, the staff determined that additional clarifications are needed to assess its consistency. This resulted in the issuance of RAIs.

SRP-LR Appendix A, Section A1.2.3.4, states that the program element describes "when," "where," and "how" program data will be collected (i.e., all aspects of activities to collect data as part of the program). Element 4 of the LRA AMP states that the parameters monitored and inspected include visual inspection of component surfaces and ultrasonic wall thickness measurements. However, it was not clear to the staff how these techniques would identify loss of material for aluminum components. By letter dated June 3, 2010, the staff issued RAI B.2.2.2-1 requesting that the applicant explain how visual inspections could identify aging effects in aluminum components.

In its response dated June 30, 2010, the applicant stated that aluminum components included in the Periodic Inspection Program are subject to loss of material due to pitting and crevice corrosion and that it will use visual inspection for identifying loss of material on accessible component surfaces. The applicant also stated that focused visual inspections of aluminum components will identify surface pits or abnormal surface roughness, which will then be entered into the corrective action program. The staff finds the applicant's response acceptable because visual inspection for surface pits or roughness is an acceptable technique for identifying loss of material due to pitting and crevice corrosion on aluminum components. The staff's concern described in RAI B.2.2.2-1 is resolved.

When the staff compared the LRA to SRP-LR Appendix A, Section A1.2.3.4 regarding the visual inspection and potential physical manipulation of elastomers for hardening and loss of strength, it was not clear to the staff: (1) what factors would come into play to determine the need to augment the visual inspections of elastomers with physical manipulations, (2) the characteristics assessed by the physical manipulations, and (3) how collected information would be quantified or otherwise used to assess component longevity.

By letter dated June 3, 2010, the staff issued RAI B.2.2.2-2 requesting that the applicant clarify the process in determining a need for physical manipulation to assist visual inspections of elastomer components, clarify the characteristics assessed by physical manipulations, and how collected information would be quantified or otherwise be used to assess component longevity.

In its response dated June 30, 2010, the applicant stated that elastomer components included in the Periodic Inspection Program are subject to the aging effect of hardening and loss of strength. The applicant stated that physical manipulation to assist in the detection of hardening and degradation is determined from the results of the initial visual inspection, which checks the material for cracking, flaking, shrinkage, swelling, or physical damage. The applicant stated that evidence of aging degradation will lead to that material being placed under the corrective action program. The staff finds the applicant's response acceptable because the applicant has clarified that physical manipulation will be used to verify aging of elastomers if signs of degradation are present, which is an acceptable technique for determining if an elastomer is aging. The staff's concern described in RAI B.2.2.2-2 is resolved.

When the staff compared the LRA to SRP-LR Appendix A, Section A1.2.3.4 recommendations on sampling, it was unclear to the staff how the applicant defined its "representative sample," population criteria, and population size. On August 18, 2010, the staff held a conference call with the applicant (ADAMS Accession No. ML102440706) to clarify the Periodic Inspection Program's sampling methodology, including how the population for each of the material-environment-aging effect combinations is being selected, and what type of engineering, design, or operating experience considerations would be used to select the sample of components for both the scheduled and supplemental inspections. During this discussion, the applicant stated that the program will ensure that for each material, environment, and aging effect combination, the applicant will conduct representative inspections as directed by formal preventive maintenance or recurring tasks within the work management system. The applicant also stated that the intent is to use existing preventive maintenance or recurring task activities augmented with new recurring task activities to address inspection of material, environments, and aging effects not adequately addressed by the current activities. The applicant further stated that if adverse conditions are identified, they will be entered into a corrective action program, discussed in the LRA, and appropriate actions will be directed including identifying and evaluating the cause and extent of the condition(s). The staff finds the applicant's response acceptable and that the "detection of aging effects" program element is consistent with the corresponding element of SRP-LR Section A.1.2.3.4, because its "representative sample" will include inspections for each material, environment, and aging effect combinations and that when degradation is found, it will be entered in the corrective action program.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4 and, therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.2.2.2 states that the Periodic Inspection Program performs visual inspections for loss of material, loss of strength, hardening, cracking, and reduction of heat transfer for selected materials and components, described under the "scope of the program" program element, and ultrasonic wall thickness measurements to detect aging effects. The applicant also stated that these periodic inspections performed on population samples with frequencies based on industry and plant experience, can be effective in identifying the extent of component degradation prior to the loss of their intended function. The applicant further stated that identified degradations will be entered into the corrective action program to determine their impact on the component's intended function, including any required repairs or subsequent monitoring and trending requirements.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Appendix A, Section A.1.2.3.5, which states that monitoring and trending activities should predict the extent of degradations to trigger timely corrective or mitigative actions. Plant-specific and industry-wide operating experience may be considered in evaluating appropriate techniques and frequencies. In addition, the program element should support quantification of aging indicators and parameters monitored to compare ongoing collected data for trending and future predictions.

Following the reviews and comparisons between LRA Section B.2.2.2 "monitoring and trending" program element with that of the SRP-LR Section A.1.2.3.5, the staff concluded that the applicant's proposed visual inspections and ultrasonic wall thickness measurements together with initiation of corrective actions would be able to determine the extent of degradation and provide timely corrective or mitigative actions, because the applicant: (1) is using techniques that would be able to determine the extent of degradation and (2) has satisfactorily described how the data will be collected and evaluated.

The staff confirmed that the "monitoring and trending" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.5 and, therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.2.2.2 states that the acceptance criteria are based on the following, for the given aging effect: (1) for loss of material, acceptance criteria are based on the original equipment design wall thickness minus allowances for corrosion and degradations; (2) for reduction of heat transfer, acceptance criteria are based on identification of fouling on the external heat transfer surfaces of cooling coils; (3) for standby diesel expansion joint cracking, acceptance criteria are based on preventing exhaust gas leakage that could impact engine operation; and (4) for hardening and loss of strength of elastomers, acceptance criteria are based on visual indications of degradation such as cracking, tears, or perforations in the material, often augmented with physical manipulations to assure the material's integrity or the need for its replacement.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which states that the acceptance criteria of the program and its basis should be described so that the need for corrective actions is evaluated. Acceptance criteria should be specific and quantifiable to ensure that the SC intended function(s) remain (including replacement) under all CLB design conditions during the period of extended operation. The program should include a methodology for analyzing the results against applicable acceptance criteria.

The staff reviewed information presented in LRA Section B.2.2.2 relevant to the "acceptance criteria" program element of the Periodic Inspection Program. The staff determined that additional clarifications are needed to assess consistency of the "acceptance criteria" program element with the corresponding element of SRP-LR Section A.1.2.3.6, which resulted in the issuance of an RAI.

SRP-LR Appendix A, Section A1.2.3.6 states that the acceptance criteria of the program and its basis should be described. The "acceptance criteria" program element of the Periodic Inspection Program states that acceptance criteria for loss of material are based on the original equipment design wall thickness and any corrosion allowance requirements. It is not clear to the staff what the acceptance criteria are for determining effects of aging on aluminum components.

By letter dated June 3, 2010, the staff issued RAI B.2.2.2-3 requesting that the applicant clarify the acceptance criteria for determining effects of aging on aluminum components.

In its response dated June 30, 2010, the applicant stated that focused visual inspection will identify any surface pitting or abnormal surface roughness and that any evidence of this type of degradation beyond minor surface corrosion is entered into the corrective action program for further evaluation by engineering staff. The applicant also stated that this engineering evaluation will determine acceptability for continued service with acceptance criteria based on the component's design requirements and component intended functions. The applicant further stated that components that cannot be determined capable of performing their intended function are repaired or replaced. The staff finds the applicant's response acceptable because the applicant has indicated the criteria against which the need for corrective actions will be evaluated. The staff's concern described in RAI B.2.2.2-3 is resolved.

The staff confirmed that the "acceptance criteria" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.6 and, therefore, the staff finds it acceptable.

<u>Operating Experience</u>. LRA Section B.2.2.2 summarizes operating experience related to the Periodic Inspection Program. The applicant stated that the proposed Periodic Inspection Program will be effective in assuring that the intended functions of systems and components within the scope of the program will be maintained for the period of extended operation. To support this statement, the applicant provided several periodic visual inspection examples of: (1) stainless steel, aluminum, and copper alloy ventilation system components exposed to plant and outdoor air; (2) stainless steel piping exposed to external salt contamination from the Delaware River, following feedback from industry operating experience observations (INPO SEN 226, SCC on a portion of safety injection system piping); and (3) elastomer components in the technical support center's ventilation fan. In the first and second examples, the applicant

stated that the results of the inspections were satisfactory and that no corrective actions were required. The third example led to a visual identification of a degraded elastomer prompting its subsequent repair. The applicant further stated that these examples demonstrate that these types of inspections performed by system owners are objective and adequate to evaluate the condition of the systems or components.

The staff reviewed this information against the acceptance criteria in SRP-LR Appendix A, Section A.1.2.3.10, which states that operating experience of the AMP, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support the conclusion that the effects of aging will be adequately managed so that the SC intended function(s) will be maintained during the period of extended operation.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.2.2 provides the UFSAR supplement for the Periodic Inspection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2. The staff also notes that the applicant committed (Commitment No. 41) to implement the new Periodic Inspection Program prior to entering the period of extended operation for managing aging of applicable components. The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its technical review of the applicant's Periodic Inspection Program, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.3 Aboveground Non-Steel Tanks

Summary of Technical Information in the Application. LRA Section B.2.2.3 describes the new Aboveground Non-Steel Tanks Program as plant-specific. The applicant stated that the program is used to manage the aging effect of loss of material on the external surfaces of aboveground non-steel tanks of which the condensate storage tank is the only component within scope. The applicant also stated that the program will apply visual inspections to the external tanks surfaces above their foundation interface, UT inspections of the tank bottom from inside the tank, and an inspection of the grout installed at the interface edge between the tank bottom and the concrete foundation. The staff notes that the applicant's inspection procedures ensure that the caulk and sealant joint between the tank and foundation interface is visually inspected during the inspection of the tank.

Staff Evaluation. The staff reviewed program elements one through six of the applicant's program against the acceptance criteria for the corresponding elements as stated in SRP-LR Section A.1.2.3. The staff's review focused on how the applicant's program manages aging effects through the effective incorporation of these program elements. The staff's evaluation of each of these elements follows.

Scope of the Program. LRA Section B.2.2.3 states that the Aboveground Non-Steel Tanks Program includes outdoor non-steel tanks of which the only one within the scope of license renewal is the condensate storage tank. The applicant stated that the program includes periodic visual inspections of the accessible tanks external surfaces, UT inspections of the tank bottom, and inspection of the grout installed at the interface edge between the tank bottom and concrete foundation. The applicant also stated that the tank vent bird screen will be visually inspected for loss of material.

The staff reviewed the applicant's "scope of the program" program element against the criteria in SRP-LR Section A.1.2.3.1, which states that the program should include the specific SCs for which the program manages aging.

The staff reviewed the LRA and noted that the condensate storage tank and its associated tank vent bird screen are the only outdoor aboveground non-steel tanks and components being managed by this AMP. The staff also noted all the other non-steel tanks within the scope of license renewal are located indoors and are managed under different AMPs (e.g., Water Chemistry Program, Periodic Inspection Program, and Closed-Cycle Cooling Water System Program). Therefore, given that each of the other non-steel tank AMR line items will be evaluated during the review of the LRA, the staff determines the applicant's scope of the program acceptable for the AMP.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1 and, therefore, the staff finds it acceptable.

Preventive Actions. LRA Section B.2.2.3 states that the program is a condition monitoring program and does not include activities for prevention or mitigation of aging effects. The applicant stated that the program includes periodic visual inspections including the grout installed at the interface edge between the tank bottom and concrete foundation, UT inspections of the tank bottom, and visual inspection of the tank vent bird screen for loss of material. The applicant also stated that a 5-year visual inspection frequency was established based on plant and industry operating experience, and provides reasonable assurance that significant aging effects will be detected and corrective actions taken prior to loss of component intended function.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which states that for condition monitoring programs, preventive activities do not need to be included in the program.

The staff reviewed the program and confirmed that for the materials (i.e., stainless steel and grout) and environments (i.e., air outdoor and soil) included, it is appropriate that this is a condition monitoring program without activities for corrosion mitigation or for corrosion prevention. Therefore, the staff determines the applicant's preventive actions are appropriate for the AMP.

The staff confirmed that the “preventive actions” program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2 and, therefore, the staff finds it acceptable.

Parameters Monitored or Inspected. LRA Section B.2.2.3 states that the program includes activities to detect the presence and extent of aging effects including general loss of material, pitting, and crevice corrosion. The applicant stated that the methods that monitor for those aging effects are visual inspection and UT. The applicant also stated that UT will quantitatively measure wall thickness of tank bottoms and focused visual inspections will detect significant loss of material due to pitting and crevice corrosion prior to loss of the tank intended function. The applicant also stated that the visual inspection will detect grout degradation that could allow water to get under the tank bottom.

The staff reviewed the applicant’s “parameters monitored or inspected” program element against the criteria in SRP-LR Section A.1.2.3.3, which states that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular SC intended function(s) and for a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects.

The staff noted that the use of ultrasonic measurements and visual inspections is consistent with standard industrial practices and the parameters monitored in GALL AMP XI.M29, “Aboveground Steel Tanks,” and has been proven to be effective in detecting significant losses of material due to the corrosion effects covered in the applicant’s program. Therefore, the staff determines the parameters to be inspected by the applicant appropriate for the aging effects addressed.

The staff confirmed that the “parameters monitored or inspected” program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3 and, therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.2.2.3 states that the Aboveground Non-Steel Tanks Program will detect loss of material aging effects on the tank external surfaces before there is a loss of the tank intended function. The applicant stated that focused visual inspections will detect significant loss of material due to pitting and/or crevice corrosion prior to loss of the in-scope tank’s intended functionality. The applicant also stated that the UT method will be applied to the inside surfaces to inspect tank bottoms for thickness reduction due to corrosion. The applicant further stated that the visual inspection of the grout and sealant materials will be conducted to detect signs that water could potentially get under the tank bottom. The applicant stated that based on industry and plant-specific operating experience, the visual inspections will be conducted with 5-year intervals, and that the UT will be conducted prior to the period of extended operation.

The staff reviewed the applicant’s “detection of aging effects” program element against the criteria in SRP-LR Section A.1.2.3.4, which states that detection of aging effects should occur before there is a loss of the SC intended function(s). The criteria also states that parameters to be monitored or inspected should be appropriate to ensure that the SC intended function will be adequately maintained for license renewal under all CLB design conditions. The criteria further states that a program based solely on detecting SC failure should not be considered as an effective AMP for license renewal. The criteria states that this program element describes “when,” “where,” and “how” program data are collected (i.e., all aspects of activities to collect data as part of the program). The criteria continue by stating that the method or technique and frequency may be linked to plant-specific or industry-wide operating experience.

The staff confirmed that the use of the applicant's methods are appropriate for detecting the aging effects covered in the program by comparing them to GALL AMP XI.M29, and that the combined use of visual inspections and UT provide sufficient detection methods to monitor corrosion effects prior to loss of the tank's intended function. Therefore, the staff determines that the parameters being used to detect the aging effects are appropriate for the aging effects addressed.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4 and, therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.2.2.3 states that the program's visual and ultrasonic examination inspections are based on industry and plant-specific operating experience. The applicant stated that wall thickness measurements will be compared to design requirements to determine if significant loss of material degradation is occurring. The applicant also stated that any significant corrosion detected as part of the inspections of this program will be entered into the corrective action program to determine the impact on the tank's intended function, required repair, and further monitoring and trending requirements.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Section A.1.2.3.5, which states that monitoring and trending activities should be described and should provide predictability of the extent of degradation and thus effect timely corrective or mitigative actions. The criteria also states that plant-specific and/or industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency. The criteria further states that this program element describes "how" the data collected are evaluated and may also include trending for a forward look, including an evaluation of the results against the acceptance criteria and a prediction regarding the rate of degradation in order to confirm that timing of the next scheduled inspection will occur before a loss of SC intended function.

The staff considers the applicant's coverage of this program element to be adequate because the applicant's description of the program includes the application of corrosion monitoring and engineering analysis when corrosion is detected on in-scope components, which is consistent with the guidance in the SRP-LR. While the applicant's program description did not specifically discuss predicting the rate of degradation, it did state that one aspect of the corrective action program is to further monitoring and trending requirements. The staff noted that the applicant's monitoring methods are adequate to ensure that corrosion issues can be addressed prior to loss of component functionality because the applicant's method of inspection and frequency of sampling is consistent with industry and plant-specific operating experience and GALL AMP XI.M29. Therefore, the staff determines that the parameters being monitored or trended are appropriate for the aging effects addressed.

The staff confirmed that the "monitoring and trending" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.5 and, therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.2.2.3 states that the acceptance criteria for the inspections that result in a quantitative value are the original equipment design wall thickness and corrosion allowance. The applicant stated that the acceptance criteria for visual inspections are qualitative unless indications of significant pitting, crevice corrosion, or other significant degradation are present which will result in an evaluation to quantify the material loss, which is then compared to the applicable design requirements. The applicant also stated that inspections are performed by qualified personnel in accordance with approved station procedures.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which states the acceptance criteria of the program and its basis should be described, including ensuring that the SC intended function(s) are maintained under all CLB design conditions during the period of extended operation. Acceptance criteria could be specific numerical values, or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria to ensure that the SC intended function(s) will be maintained under all CLB design conditions. Information from available references may be cited. The criteria also states that acceptance criteria, which do permit degradation, are based on maintaining the intended function under all CLB design loads. The criteria further states that qualitative inspections should be performed to the same predetermined criteria as quantitative inspections by personnel in accordance with ASME Code and through approved site-specific programs.

The staff considers the applicant's coverage of this program element to be adequate because the applicant's program description includes details on the method to be followed in response to observed corrosion effects, which is consistent with the guidance in the SRP-LR. The staff noted that the applicant's program relies on established acceptance criteria, such as the original manufacturer's specifications, including wall thickness for the specific component type and materials to be covered. The staff also noted that qualified personnel are used to perform inspections in accordance with approved plant procedures. Therefore, the staff determines that the acceptance criteria being used to evaluate aging effects are appropriate for the aging effects addressed.

The staff confirmed that the "acceptance criteria" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.6 and, therefore, the staff finds it acceptable.

Operating Experience. LRA Section B.2.2.3 summarizes operating experience related to the Aboveground Non-Steel Tanks Program. The applicant stated that based on industry operating experience, visual inspections were conducted to address the potential for accelerated corrosion due to salt contamination from the Delaware River. The applicant also stated that the inspections performed in 2005 and 2007 resulted in no indications of age-related degradation. The applicant further stated that maintenance history searches did not yield any evidence of age-related degradation. The applicant stated that the good physical condition of the in-scope tanks supports the sufficiency of the program's intended frequency of 5 years between inspections.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which states that the operating experience information provided should provide objective evidence that the effects of aging will be adequately managed so that the intended function(s) of the in-scope SCs are maintained during the period of extended operation.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SCCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.2.3 provides the UFSAR supplement for the Aboveground Non-Steel Tanks Program.

The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.4-2. The staff also notes that the applicant committed (Commitment No. 42) to implement the new Aboveground Non-Steel Tanks Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its technical review of the applicant's Aboveground Non-Steel Tanks Program, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.4 Buried Non-Steel Piping Inspection

Summary of Technical Information in the Application. LRA Section B.2.2.4 as supplemented by letter dated September 1, 2010, and October 29, 2010, describes the existing Buried Non-Steel Piping Inspection Program as a plant-specific program. The applicant stated that the Buried Non-Steel Piping Inspection Program is a condition monitoring program used to manage buried reinforced concrete piping and components in its service water system for cracking, loss of bond, increase in porosity and permeability, and loss of material. The Buried Non-Steel Piping Inspection Program also manages buried stainless steel piping and components in the condensate storage and transfer system and fire protection systems for loss of material. The applicant also stated that the program relies on visual inspections of the external surfaces of the piping and coatings conducted as part of opportunistic and focused excavations of buried, in-scope piping and components. The applicant further stated that areas with high susceptibility of exterior surface degradation, consequence of failure, and areas with a history of exterior surface degradation problems are prioritized for inspection.

Staff Evaluation. The staff reviewed program elements one through six of the applicant's program against the acceptance criteria for the corresponding elements as stated in SRP-LR Section A.1.2.3. The staff's review focused on how the applicant's program manages aging effects through the effective incorporation of these program elements. The staff's evaluation of each of these elements follows.

Scope of the Program. LRA Section B.2.2.4 states that the Buried Non-Steel Piping Inspection Program is an existing program that manages the aging effects of cracking, loss of bond, loss of material, and increased porosity and permeability. The applicant stated that the program manages non-steel buried piping and buried stainless steel piping and components within the service water system, condensate storage and transfer system, and fire protection system.

The staff reviewed the applicant's "scope of the program" program element against the criteria in SRP-LR Section A.1.2.3.1, which states that the program should include the specific SCs for which the program manages aging.

The staff reviewed the applicant's program basis documents and LRA Sections 2.3 and 3.0. The staff determines that the LRA provides a list of the specific aging effects to be managed as well as all component types and systems that are covered by this program.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1 and, therefore, the staff finds it acceptable.

Preventive Actions. LRA Section B.2.2.4 states that this program is a condition monitoring program that relies on opportunistic and focused inspections, and it is not a preventive or mitigative program.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which states that for condition monitoring programs, preventive activities do not need to be included in the program.

The staff reviewed the program and confirmed that it is a condition monitoring program without activities for corrosion mitigation or for corrosion prevention.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2 and, therefore, the staff finds it acceptable.

Parameters Monitored or Inspected. LRA Section B.2.2.4 states that the program includes opportunistic or focused inspections to detect the presence of cracking, loss of bond, increases in porosity and permeability, and loss of material for non-steel buried piping and components. The applicant stated that the inspections identify coating degradation if piping and components are coated and base material degradation if piping and components are uncoated. The applicant further stated that this program is not a performance monitoring program nor is it a preventive or mitigative program.

The staff reviewed the applicant's "parameters monitored or inspected" program element against the criteria in SRP-LR Section A.1.2.3.3, which states that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular SC intended function(s) and for a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects.

The staff noted that the use of visual inspection is consistent with standard industrial practices and GALL AMP XI.M34, "Buried Piping and Tanks Inspection," and has been proven to be effective in detecting significant losses of material or coating degradation due to the aging effects covered in the applicant's program. Therefore, the staff determines that the parameters to be inspected by the applicant are appropriate for the aging effects addressed.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3 and, therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.2.2.4 states that the visual inspections to detect the aging effects being managed by this program will be in accordance with accepted industrial standards. The applicant stated that engineering evaluations will determine the need for expanded inspection scope if initial inspection results are unacceptable. The applicant also stated that at least one opportunistic or focused inspection will be performed within 10 years prior to the period of extended operation and within the first 10 years of the period of extended operation. The applicant further stated that plant operating experience (i.e., no failures of buried non-steel piping due to external aging effects) supports this frequency of inspection.

The staff reviewed the applicant's "detection of aging effects" program element against the criteria in SRP-LR Section A.1.2.3.4, which states that detection of aging effects should occur before there is a loss of the SC intended function(s). The criteria also states that parameters to be monitored or inspected should be appropriate to ensure that the SC intended function will be adequately maintained for license renewal under all CLB design conditions. The criteria further states that a program based solely on detecting SC failure should not be considered as an effective AMP for license renewal. The criteria states that this program element describes "when," "where," and "how" program data are collected (i.e., all aspects of activities to collect data as part of the program). The criteria continue by stating that the method or technique and frequency may be linked to plant-specific or industry-wide operating experience.

The staff confirmed that the use of the applicant's methods are appropriate for detecting the aging effects covered in the program by comparing them to GALL AMP XI.M34, "Buried Piping and Tanks Inspection," and that the use of visual inspections provides sufficient detection methods to monitor degradation of coatings and corrosion effects prior to loss of the buried non-steel piping intended function. Additionally, the program specifies the periodicity of the inspections, location of the inspections relative to the material type and risk ranking, and that the inspections will be performed by excavated direct inspection of the pipe. Therefore, the staff determines that the parameters being used to detect the aging effects are appropriate for the aging effects addressed.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4 and, therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.2.2.4 states that opportunistic and focused inspections are appropriate and adequate to detect aging effects prior to piping and component loss of intended function. The applicant stated that significant degradation identified by the visual inspections will be entered into the corrective action program and an engineering evaluation will quantify the results, which will either demonstrate acceptability or specify a repair or replacement. The applicant also stated that the engineering evaluations will determine the need for follow-up exams to monitor progression of degradation, ensuring that inspections will occur prior to loss of function. The applicant further stated that by trending the data, the engineering evaluation will determine if the sample size must be expanded to determine the extent of degradation or if the frequency of inspections is acceptable.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Section A.1.2.3.5, which states that monitoring and trending activities should be described, and they should provide predictability of the extent of degradation and thus effect timely corrective or mitigative actions. The criteria also states that plant-specific and/or industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency. The criteria further states that this program element describes "how" the data collected are evaluated and may also include trending for a forward look, including an evaluation of the results against the acceptance criteria and a prediction regarding the rate of degradation in order to confirm that the timing of the next scheduled inspection will occur before a loss of SC intended function.

The staff considers the applicant's coverage of this program element to be adequate because the applicant's description of the program includes the application of engineering analysis and trending when corrosion is detected on in-scope components. The staff noted that the applicant's monitoring and trending methods are adequate to ensure that corrosion issues can be addressed prior to loss of component functionality, and inspection frequencies will be adjusted by engineering evaluation if necessary based on inspection results.

The staff confirmed that the "monitoring and trending" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.5 and, therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.2.2.4 states that the acceptance criteria to be applied to the results of inspections are the applicable regulatory or industry requirements for the component being inspected. The applicant stated that the specific acceptance criteria relating to localized pipe wall thinning is contained in engineering documents, and is used in engineering evaluations of observed corrosion. The applicant also stated that the visual inspection process is qualitative, and in instances where significant corrosion is observed by visual inspection, additional evaluation will occur including quantifying material loss and comparing it to the applicable design requirements based on industry standards. The applicant further stated that inspections are performed by qualified personnel in accordance with approved procedures.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which states the acceptance criteria of the program and its basis should be described, including ensuring that the SC intended function(s) are maintained under all CLB design conditions during the period of extended operation. Acceptance criteria could be specific numerical values, or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria to ensure that the SC intended function(s) will be maintained under all CLB design conditions. Information from available references may be cited. The criteria also state that acceptance criteria, which do permit degradation, are based on maintaining the intended function under all CLB design loads. The criteria further state that qualitative inspections should be performed to the same predetermined criteria as quantitative inspections by personnel in accordance with ASME Code and through approved site-specific programs.

The staff considers the applicant's coverage of this program element to be adequate because the applicant's program description includes details on the method to be followed in response to observed corrosion effects, it relies on established acceptance design based criteria for the specific component and materials to be covered, and it relies on standard industry practices. The staff also noted that qualified personnel are used to perform inspections in accordance with approved plant procedures. Therefore, the staff determines that the acceptance criteria being used to evaluate aging effects are appropriate for the aging effects addressed.

The staff confirmed that the "acceptance criteria" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.6 and, therefore, the staff finds it acceptable.

The staff notes that even though the Buried Non-Steel Piping Inspection Program is a plant-specific program, the applicant has demonstrated consistency with each of the program elements in GALL AMP XI.M34 except that the materials are non-steel (i.e., reinforced concrete, stainless steel) while the scope of GALL AMP XI.M34 includes only steel components (e.g., steel, gray cast iron, ductile cast iron). Based on recent industry operating experience, the staff requires further information related to the applicant's plant-specific operating experience and the quality of backfill in the vicinity of buried pipe. The staff issued RAIs B.2.1.24 and

B.2.1.24-02 and their evaluations are documented in the "operating experience" program element.

Operating Experience. LRA Section B.2.2.4 summarizes operating experience related to the Buried Non-Steel Piping Inspection Program. The applicant stated that the program has been effective as evidenced by the fact that there have been no underground leaks that developed as a result of failure of the external surface of buried stainless steel or reinforced concrete piping. The applicant also described an instance of operating experience that was related to a condition of internal surface degradation which provided an opportunistic external surface coating inspection of excavated piping which was observed to be intact and no corrosion was detected on the exterior pipe surface.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which states that the operating experience information provided should provide objective evidence that the effects of aging will be adequately managed so that the intended function(s) of the in-scope components and structures are maintained during the period of extended operation.

Given that there have been a number of recent industry events involving leakage from buried or underground piping, the staff needed further information to evaluate the impact that these recent industry events might have on the applicant's Buried Piping and Tanks Inspection Program. By letter dated August 6, 2010, the staff issued RAI B.2.1.24 requesting that the applicant provide information regarding how the applicant will incorporate the recent industry OE into its aging management reviews and programs.

In its response dated September 1, 2010, the applicant stated that there have been no leaks of buried in-scope piping as a result of external corrosion. The applicant also stated that it has risk ranked all buried piping in accordance with NACE and EPRI guidelines and the NEI Industry Initiative on Buried Piping, and based on these risk rankings, inspections of the external surfaces of the pipe are scheduled and conducted. The applicant stated that it has committed to conduct excavated visual inspections of at least 8 linear feet of buried pipe, when practical, in each material group, which includes buried reinforced concrete piping and buried stainless steel piping, during each 10-year period, beginning 10 years prior to entry into the period of extended operation.

Based on its review, the staff requested clarification on the applicant's response. By letter dated October 12, 2010, the staff issued RAI B.2.1.24-02 requesting that the applicant: (a) define what is meant by excavating 8 feet of pipe when practical, state what alternative means will be utilized to determine the condition of the buried pipe, or justify why inspecting less than 8 feet is sufficient to provide a reasonable assurance of the condition of the pipe and coatings; (b) clarify if any in-scope buried pipe contains hazardous material and if applicable, state what percent of in-scope buried pipe containing hazardous material will be inspected; and (c) provide details on the quality of backfill in the vicinity of in-scope buried pipes. This was considered to be open item OI 3.0.3.2.12-1 during the issuance of the SER with open items.

In its response dated October 29, 2010, the applicant stated that, in reviewing candidate inspection sites, it has determined that there is no need to have the phrase "when practical" in relation to examining 8 feet of pipe and the RAI response was subsequently revised accordingly to retract the words "when practical." Therefore, the applicant concluded there is no need to provide alternative inspection details for less than 8-foot inspections.

Also, the applicant stated that the only buried in-scope piping containing tritium exceeding EPA drinking water limits is stainless steel piping that is cathodically protected in the condensate storage and transfer system. The applicant subsequently revised its commitment to specifically name the stainless steel piping in the condensate storage and transfer system to be inspected each 10-year period, starting 10 years prior to the period of extended operation, which will result in 3 percent of the piping being inspected each 10-year period. The total length of the line is approximately 250 linear feet. An 8-foot segment of one of these lines will be selected to fulfill the commitment to excavate and inspect a stainless steel pipe segment in each 10-year period.

Finally, the applicant stated that buried piping was backfilled during original construction in accordance with construction backfill specifications. The applicant stated the construction backfill specifications as:

> Bedding material within six inches of the buried coated piping will consist of sand, or an approved well graded granular material free from stones greater than 3/8 inches in diameter, or a lean fillcrete or sandcrete. The backfill requirements for the Service Water System pre-stressed concrete pipe were difference than requirements for coated metallic pipe since coating damage is not a concern. Bedding material for this piping (within 6 inches of the pipe) was required to be lean concrete or crushed stones not greater that 1 inch diameter.

The buried pipe inspection procedures require that the condition of backfill and coatings be documented. Review of inspection records note that coatings were found in acceptable condition.

Based on its review, the staff finds the applicant's response to RAI B.2.1.24 and RAI B.2.1.24-02 acceptable because: (a) there have been no leaks of buried in-scope piping; (b) the applicant will excavate a minimum of 8 feet of pipe during each inspection; (c) at least one excavated visual inspection will be conducted on buried reinforced concrete piping and components during each 10-year period, beginning 10 years prior to entry into the period of extended operation; (d) 3 percent of the buried stainless steel piping containing tritium exceeding EPA drinking water limits will be inspected each 10-year period beginning 10 years prior to the period of extended operation; and (e) the applicant has appropriate backfill specifications and inspections have demonstrated that coatings are in acceptable condition. The staff's concerns described in RAI B.2.1.24 and RAI B.2.1.24-02 are resolved. Open item OI 3.0.3.2.12-1 is closed.

Based on its audit and review of the application, resolution to RAI B.2.1.24 and RAI B.2.1.24-02, and closure of open item OI 3.0.3.2.12-1, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.2.4 provides the UFSAR supplement for the Buried Non-Steel Piping Inspection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.3-2.

The staff also notes that the applicant committed (Commitment No. 43) to enhance the existing Buried Non-Steel Piping Inspection Program for managing aging of applicable components prior to the period of extended operation. Specifically, the applicant committed to include:

1. At least one (1) opportunistic or focused excavation and inspection will be performed on buried reinforced concrete piping and components during each ten (10) year period, beginning ten (10) years prior to entry into the period of extended operation.

2. At least one (1) opportunistic or focused excavation and inspection will be performed on Condensate Storage and Transfer System buried stainless steel piping and components, which contain fluid that exceeds EPA drinking water limits, during each ten (10 year period, beginning ten (10) years prior to entry into the period of extended operation.

3. Guidance for inspection of concrete aging effects.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its technical review of the applicant's Non-Steel Buried Piping Inspection Program, resolution to RAI B.2.1.24 and RAI B.2.1.24-02, and closure of open item OI 3.0.3.2.12-1, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.5 Boral Monitoring Program

Summary of Technical Information in the Application. LRA Section B.2.2.5 describes the existing Boral Monitoring Program as a plant-specific program that monitors the Boral test coupon inspections and/or testing results at other BWR sites, and if the testing results indicate a problem with the function of the Boral (i.e., ability to absorb neutrons), HCGS will initiate inspection and/or testing of its Boral test coupons in the SFP.

Staff Evaluation. The staff reviewed program elements one through six of the applicant's program against the acceptance criteria for the corresponding elements as stated in SRP-LR Section A.1.2.3. The staff's review focused on how the applicant's program manages aging effects through the effective incorporation of these program elements. The staff's evaluation of each of these elements follows.

The staff reviewed information presented in LRA Section B.2.2.5 relevant to the "preventive actions," "detection of aging effects," and "monitoring and trending" program elements of the Boral Monitoring Program. The applicant stated, "The assumption is that the spent fuel pool environments, including the pool's water chemistry and radiation field, and the Boral material characteristics are consistent enough so that the results at other BWR sites are representative of the results if the Hope Creek Boral test coupons were inspected and/or tested.

LR-ISG-2009-01, "Aging Management of Spent Fuel Pool Neutron-Absorbing Materials other than Boraflex," cited specific examples of industry operating experience that have shown extrapolations on plant-specific data that were incorrect in trying to determine the future condition of neutron-absorbing material in SFPs. The staff clarified that an applicant should consider both plant-specific and industry operating experience in an LRA, and that the plant-specific operating experience should include data from an ongoing inspection and monitoring program." The staff determined that additional clarifications was needed, which resulted in the issuance of an RAI.

By letter dated April 14, 2010, the staff issued RAI 2.2.5-1 requesting that the applicant discuss its plan to implement changes to the Boral Monitoring Program that will include regular inspections of the SFP test coupons at HCGS.

In its response dated May 11, 2010, the applicant stated that based on recent industry operating experience and issues outlined in LR-ISG-2009-01, the Boral Monitoring Program will be enhanced to include inspection, testing, and evaluation of one coupon prior to the period of extended operation and one coupon within the first 10 years after entering the period of extended operation. Testing will include dimensional and neutron attenuation measurements with an acceptance criteria of no more than a 10 percent increase in thickness and no more than a 5 percent decrease in Boron-10 areal density.

The staff finds the applicant's response acceptable because the applicant has committed to (Commitment No. 44) an enhancement of the existing program to implement prior to the period of extended operation an inspection, testing, and evaluation of one coupon from the SFP prior to the period of extended operation, and one coupon within the first 10 years after entering the period of extended operation. This verifies that there are no plant-specific conditions in the SFP that could degrade the capability of the Boral to absorb neutrons. Additionally, this enhancement aligns the Boral Monitoring Program with LR-ISG-2009-01, which states the applicant should demonstrate in its specific SFP environment, for its specific material(s), that degradation has not occurred in a manner that could adversely impact the material's intended function. The staff's concern described in RAI 2.2.5-1 is resolved.

Scope of the Program. LRA Section B.2.2.5 states that the Boral Monitoring Program is an existing program that monitors the Boral test coupon inspection and/or testing results at other BWR sites. If these results indicate a problem with the Boral neutron-absorbing material potentially affecting its intended function (i.e., absorb neutrons), HCGS will initiate inspection and/or testing of its Boral test coupons in the SFP. The applicant stated that the scope will be enhanced to include inspection, testing, and evaluation of one coupon from the SFP prior to the period of extended operation, and one coupon within the first 10 years after entering the period of extended operation. Testing will include dimensional and neutron attenuation measurements.

The staff reviewed the applicant's "scope of the program" program element against the criteria in SRP-LR Section A.1.2.3.1, which states that the specific program necessary for license renewal should be identified, and the scope of the program should include the specific SCs that the program manages.

The staff noted that the scope of the applicant's Boral Monitoring Program appropriately identifies the specific program used and the components monitored by the program. In response to RAI 2.2.5-1, the applicant expanded the scope of the program to include testing of one coupon prior to entering the period of extended operation and one coupon within the first 10 years of entering the period of extended operation. This enhancement is appropriate because it verifies that there are no plant-specific conditions in the SFP that could degrade the capability of the Boral to absorb neutrons. Additionally, this enhancement aligns the Boral Monitoring Program with LR-ISG-2009-01, which states the applicant should demonstrate in its specific spent fuel pool environment, for its specific material(s), that degradation has not occurred in a manner that could adversely impact the material's intended function. Therefore, the staff finds that the scope of the applicant's Boral Monitoring Program satisfies the criteria defined in SRP-LR Section A.1.2.3.1 and is acceptable.

Preventive Actions. LRA Section B.2.2.5 states that the Boral Monitoring Program is comprised of the AMPs at other BWR sites and as such, is a condition monitoring program and does not rely on preventive actions.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which states that for condition or performance monitoring programs, they do not rely on preventive actions and thus, this information need not be provided.

The staff noted the Boral Monitoring Program is a condition monitoring program and confirmed that the applicant's AMP appropriately identifies the conditions that are monitored by the program. Therefore, the staff finds that the applicant's Boral Monitoring Program satisfies the criterion defined in SRP-LR Section A.1.2.3.2 and is acceptable.

Parameters Monitored or Inspected. LRA Section B.2.2.5 states that the Boral Monitoring Program includes Boral surveillance inspections performed by other BWRs, and includes visual inspections and/or testing of Boral test specimens or coupons to monitor changes in physical properties of the Boral in the SFP. The applicant also stated that examination of the Boral test coupon includes visual examination and photography, and may include dimensional measurements, weight and density/specific gravity measurement, and neutron attenuation measurement. The Boral test coupon is visually examined to detect aging affects such as corrosion, pitting, swelling, or other degradation. The Boral test coupon may be photographed if, in the judgment of the technician, there is any information of significance that should be photographically documented. Dimensional measurements such as length, width, and thickness are taken to document if physical changes are occurring in the Boral test coupon. The Boral test coupon is weighed and in some instances, the density and specific gravity is calculated to determine if there are any changes in the physical properties. A measurement by neutron attenuation is performed to determine if there has been any change in the Boron-10 content. These inspections and/or testing are performed by a qualified contractor or measurement laboratory and will ensure against unexpected degradation of the Boral neutron-absorbing material. In response to RAI 2.2.5-1, the applicant enhanced the parameters monitored or inspected by adding that one coupon from the SFP will be inspected, tested, and evaluated prior to the period of extended operation and one coupon will be inspected, tested, and evaluated within the first 10 years after entering the period of extended operation. Testing will include dimensional and neutron attenuation measurements.

The staff reviewed the applicant's "parameters monitored or inspected" program element against the criteria in SRP-LR Section A.1.2.3.3, which states that for a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects. The enhancement provided by the applicant, in response to RAI B.2.2.5-1, provides reasonable assurance that plant-specific conditions at HCGS will not allow Boral to degrade and go unnoticed in the SFP, and thereby compromise the Boral condition monitoring program.

The staff confirmed that the “parameters monitored or inspected” program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3 and, therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.2.2.5 states that the Boral surveillance performed by other BWR sites include visual inspections and/or testing of the Boral test specimens or coupons to monitor changes in physical properties of Boral. These Boral test coupons are in the SFP and subject to irradiated fuel assemblies to ensure that the Boral test coupons of the BWR sites are representative of their Boral in their SFP storage racks. Examination of the Boral test coupons include visual examination and photography, and may include dimensional measurements, weight and density/specific gravity measurement, and neutron attenuation measurement. A measurement by neutron attenuation is performed to determine if there has been any change in the Boron-10 content. In response to RAI 2.2.5-1, the applicant enhanced the parameters monitored or inspected by adding that one coupon from the SFP will be inspected, tested, and evaluated prior to the period of extended operation, and one coupon will be inspected, tested, and evaluated within the first 10 years after entering the period of extended operation. Testing will include dimensional and neutron attenuation measurements.

The staff reviewed the applicant’s “detection of aging effects” program element against the criteria in SRP-LR Section A.1.2.3.4, which states that detection of aging effects should occur before there is a loss of the SC intended function(s). The parameters to be monitored or inspected should be appropriate to ensure that the SC intended function(s) will be adequately maintained for license renewal under all CLB design conditions. This includes aspects such as method or technique (e.g., visual, volumetric, surface inspection), frequency, sample size, data collection, and timing of new/one-time inspections to ensure timely detection of aging effects. The parameters to be monitored or inspected should be clearly linked to the aging effects being managed. The program element describes “when,” “where,” and “how” the data are collected. The method or technique and frequency may be linked to plant-specific or industry-wide operating experience, and when sampling is used, the basis for the inspection population and sample size should be provided. The sample size should be based on such aspects as the specific aging effect, location, existing technical information, system and structure design, materials of construction, service environment, or previous failure history. The samples should be biased toward locations most susceptible to the specific aging effect of concern in the period of extended operation. Provisions should also be included on expanding the sample size when degradation is detected in the initial sample.

The applicant’s “detection of aging effects” program element uses many tests that assess the physical condition of the Boral test panels in the SFP. The enhancement provided by the applicant in response to RAI 2.2.5-1 is appropriate because it directly measures the loss of the key function (i.e., absorbing neutrons) that the Boral provides. The enhancement provides reasonable assurance that plant-specific conditions at HCGS will not allow Boral to degrade and go unnoticed in the SFP. The staff confirmed that the “detection of aging effects” program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4 and, therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.2.2.5 states that the Boral Monitoring Program monitors the Boral test coupon inspection or testing results at other BWR sites. If these results indicate a problem with the Boral neutron-absorbing material potentially affecting its intended function (i.e., absorb neutrons), HCGS will initiate inspection and/or testing of its Boral test coupons in the SFP. The test results will be used to assess the condition of the Boral neutron-absorbing material used in the HCGS SFP storage racks. The test results will provide the information and data needed to perform trending for indication of a potential degradation that may impact the performance of the Boral neutron-absorbing material. A summary of test results received from other BWR Boral surveillance will be entered into the plant document retrieval system. If these results indicate a problem with the Boral neutron-absorbing material affecting its intended function (i.e., absorb neutrons), HCGS will initiate inspection and/or testing of its Boral test coupons.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Section A.1.2.3.5, which states that monitoring and trending activities should be described, and they should provide predictability of the extent of degradation and thus effect timely corrective or mitigative actions. Plant-specific and/or industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency. The methodology for analyzing the inspection or test results against the acceptance criteria should be described. The staff confirmed that the "monitoring and trending" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.5 and, therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.2.2.5 states that the Boral Monitoring Program monitors the Boral test coupon inspection and/or testing at other BWR sites. HCGS will request test reports from the Boral surveillance programs of these other sites every 2 years for evaluation and trending. These surveillance programs have acceptance criteria that are focused on the type of inspection and/or testing that are performed within the surveillance program. The surveillance performed by other sites may include visual inspections and/or testing of the Boral test specimens or coupons. The surveillance programs performed by other sites vary from qualitative programs that perform visual inspections only, to quantitative programs that also perform dimensional measurements and testing of the Boron-10 content.

The applicant also stated that the acceptance criteria used for the Boral is based on the type of test results that are obtained from the other site's test reports. For sites that perform only a qualitative visual examination, the HCGS qualitative acceptance criteria will be based on those results. If the conclusion from another site's test report indicates satisfactory results, no additional action is required but to document the receipt of that test report for trending. If the test report conclusion indicates performance less than satisfactory, the test report information will be entered into the corrective action program for further evaluation. The corrective action program will perform an evaluation to determine if the test results are acceptable or if further action is required, such as requesting additional previous or historical test results from the same site that can be used for correlating trends of the Boral performance. If, as a result of historical trending, these test results show a divergence or inconsistency that indicates potential degradation of the Boral's performance, corrective actions will be initiated. This could trigger the requirement to retrieve one Boral test coupon from the HCGS SFP and initiate inspection and/or testing and evaluation. For those sites that perform quantitative coupon examinations, the quantitative acceptance criteria are: (1) the increase in thickness at any point should not exceed 10 percent of the initial thickness at that point, and (2) a decrease of no more than 5 percent in Boron-10 content, as determined by neutron attenuation, is acceptable. If a site's test report indicates satisfactory results, no additional action is required but to document the receipt of that test report for trending. If the test report indicates at least one of the two acceptance criteria is unsatisfactory, the test report information will be entered into the corrective action program for further evaluation. Additionally, this could trigger the requirement to retrieve one Boral test coupon from the SFP and initiate inspection, testing, and evaluation. The enhancement provided by the applicant in response to RAI 2.2.5-1 stated that the acceptance criteria, for the dimensional and neutron attenuation measurements that are to be performed, include no more than a 10 percent increase in thickness and no more than a 5 percent decrease in Boron-10 areal density.

The staff reviewed information presented in LRA Section B.2.2.5 relevant to the "acceptance criteria" program element of the Boral Monitoring Program. The applicant stated:

> If the test report conclusion indicates at least one of the two acceptance criteria is unsatisfactory, the test report information will be entered into the Hope Creek corrective action program for further evaluation. Additionally, this could trigger the requirement to retrieve one Boral test coupon from the Hope Creek spent fuel pool and initiate inspection, testing, and evaluation in accordance with the Boral Monitoring Program.

The staff determined that additional clarifications are needed, which resulted in the issuance of an RAI.

By letter dated April 14, 2010, the staff issued RAI 2.2.5-2 requesting that the applicant describe the test results that would require an SFP test coupon to be retrieved, inspected, tested, and evaluated.

In its response dated May 11, 2010, the applicant stated that the following situations from test results from another BWR would be entered into the corrective action program and the evaluation would verify the validity of the information, determine its applicability to HCGS, and evaluate the potential impact on the spent fuel rack criticality analysis: (1) test results do not meet acceptance criteria at the BWR from which the coupon came, (2) test results would not meet acceptance criteria at HCGS, (3) test results indicated a reduction in neutron-absorbing capability outside of the variation attributed to measurement uncertainty, (4) test results generate corrective actions involving Boral material condition at the BWR from which the coupon came, (5) test results may be outside of expectations for a single population with common characteristics.

The applicant also stated that testing of HCGS Boral test coupons would be triggered if: (1) test results from other BWRs indicate a reduction in the neutron-absorbing capability of Boral that, if occurred at HCGS, could challenge the HCGS SFP criticality analysis; or (2) test results from other BWRs indicate a statistical variation impacting the intended function of Boral to absorb neutrons that is outside of the expectations for a single population with common characteristics.

The staff finds the applicant's response acceptable because the applicant has specifically described situations in the test results that would require an SFP test coupon to be retrieved, inspected, tested, and evaluated. The staff's concern described in RAI 2.2.5-2 is resolved.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which states that the acceptance criteria of the program and its basis should be described and the acceptance criteria, against which the need for corrective actions will be evaluated, should ensure that the SC intended function(s) are maintained under all CLB design conditions during the period of extended operation. The program should include a methodology for analyzing the results against applicable acceptance criteria. SRP-LR Section A.1.2.3.6 also states that acceptance criteria could be specific numerical values, or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria to ensure that the SC intended function(s) will be maintained under all CLB design conditions.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6 and, therefore, the staff finds it acceptable.

Operating Experience. LRA Section B.2.2.5 summarizes operating experience related to the Boral Monitoring Program. The applicant provided the following examples of operating experience as objective evidence that the Boral Monitoring Program will be effective in assuring that intended function of the Boral in the SFP will be maintained consistent with the CLB for the period of extended operation:

(1) Trending recent test results from other BWR sites for the past 5 years demonstrates that the Boral neutron-absorbing material is performing satisfactorily and no significant degradations have been observed or documented. Industry operating experience was obtained from seven BWR sites for Boral test coupons. These seven test reports show no aging effect significantly impacting the intended function. Using the operating experience from existing Boral surveillance programs at these other BWR sites provides a technical basis to demonstrate that HCGS does not need to implement an inspection and/or testing surveillance program of its Boral test coupons. Below is a summary of the industry operating experience for these seven BWR sites:

    These BWR plants submit their Boral test coupon(s) to a qualified vendor for inspection and testing in accordance with the vendor's Boral surveillance program. The inspection and testing of these test coupon(s) generally involves visual observations and photography, dimensional measurements (length, width, and thickness), weight and density determinations, and neutron attenuation measurements. Additionally, most of the BWR plants included Boron-10 areal density measurements with the surveillance program. The vendor prepares a report documenting the inspection and testing results and submits the report to the BWR plant. The following summarizes the inspection and testing results from the various BWR plants:

    The visual inspections of the coupon showed that with the exception of some localized pitting and some blistering of the aluminum skin of the coupons exposed to the SFP water, the condition of the coupons were as expected. It was noted that both the pitting and blistering were conditions of appearance and did not affect the function of the material. Within the accuracy of the measurements for the length, width, and thickness measurements, there were no significant changes from the initial pre-irradiated benchmarked measurements. The coupon showed a slight increase in weight and density that were within the expected accuracy of the measurements. The neutron attenuation test results showed that there was no loss of Boron-10 from the coupon. The conclusion from the inspection and tests results was that the Boral neutron-absorbing material in the spent fuel storage racks have retained their dimensional and neutron-absorption properties and are capable of continuing to perform their intended function to absorb neutrons.

    The summary of the inspection and testing results for the seven BWR plants discussed above provides objective evidence that the use and trending of industry operating experience demonstrates that the Boral neutron-absorbing material will be capable of continuing to perform its intended function of absorbing neutrons.

(2) HCGS has had no fuel assembly or blade guide movement impacted by Boral deformation (e.g., swelling, blistering). Almost every cell of the SFP racks have been accessed except for those cells listed as "DO NOT USE." Station procedure "Supplemental Hope Creek Special Nuclear Material and Core Component Storage

Information," describes the SFP cells that are considered as "DO NOT USE" cells. Older fuel assemblies (i.e., early plant discharges) have been moved to support dry cask storage campaigns and thermal management requirements. There have been no problems experienced when either removing fuel assemblies from these cells or inserting other fuel assemblies into these cells. There are 15 cells on the "DO NOT USE" list due to high cell friction. These cells failed drag tests in 1989 (1 cell) and 1992 (14 cells) soon after installation of the SFP racks and are thus not attributable to Boral deformation. The SFP racks were installed in multiple phases at HCGS. The other cells on this "DO NOT USE" list have interference problems (i.e., with hangers, equipment stored in the SFP, identification strips, the refueling bridge), have damage at the top of the cells, contain failed fuel assemblies, or contain other equipment (i.e., dummy bundle). There is one cell where the fuel assembly sits high in the cell, but this behavior has not been attributed to Boral deformation. Camera inspection did not show Boral swelling or blistering. Therefore, based on the actual usage of the SFP racks, HCGS has no problems with the Boral performance and there is reasonable assurance that the HCGS Boral performance is no different from the industry Boral performance. It is acceptable to continue to monitor industry Boral performance rather than perform inspections and/or testing of the HCGS Boral test coupons.

The staff reviewed information presented in LRA Section B.2.2.5 relevant to the "operating experience" program element of the Boral Monitoring Program. The staff had concerns about the applicant's conclusion that HCGS has had no fuel assembly or blade guide movement impacted by Boral deformation. The applicant also stated that almost every cell of the SFP racks have been accessed except for those cells listed as "DO NOT USE." The staff determined that additional clarifications are needed, which resulted in the issuance of an RAI.

By letter dated April 14, 2010, the staff issued RAI 2.2.5-3 requesting that the applicant provide the following regarding spent fuel racks: (1) if and how the racks are vented, (2) what constitutes a drag test, and (3) the basis for the conclusion that the 15 cells marked as "DO NOT USE" did not suffer from Boral deformation.

In its response dated May 11, 2010, the applicant provided further explanation that:

(1) The HCGS SFP contains 22 high-density racks. These racks use Boral as the neutron absorber. The Boral sheets are vented and exposed to SFP water. Each Boral sheet is held in place against the cell wall by a stainless steel wrapper. The wrapper is not sealed around the Boral sheet. The wrapper is spot welded to the cell wall. All Boral test coupons are vented and exposed to the SFP water. The HCGS SFP contains one low-density rack. This rack is used to store control rods and defective fuel storage containers. It does not use any neutron absorbers.

(2) Drag testing is performed for two purposes: (a) to verify that the spent fuel rack cell was fabricated with the required dimensions and (b) to detect deformation in the walls of a spent fuel rack cell once the spent fuel racks are placed in service. Drag testing can be performed under dry or wet conditions. A drag test consists of lowering and then withdrawing a test gauge or dummy bundle while monitoring a load cell for elevated friction or drag. The acceptance criteria for the drag test is the maximum allowed change in the load cell reading from the nominal value. A drag test begins by lowering the test gauge or dummy bundle into the spent fuel rack cell while monitoring a load cell. A decrease in the load cell reading more than the acceptance criteria is a drag test

failure. If the test gauge of dummy bundle hangs up prior to full insertion, it is a drag test failure. The test gauge or dummy bundle is then withdrawn while monitoring the load cell reading. An increase in the load cell reading more than the acceptance criteria is a drag test failure. A test failure is entered into the corrective action program for evaluation. The evaluation could specify repairs, require additional testing, place restrictions on usage of the cell, or prevent usage of the cell.

(3) The 15 cells marked “DO NOT USE” failed dry drag tests that were performed as part of the post-fabrication testing of the associated spent fuel racks prior to their placement in the SFP. Following placement of the associated spent fuel racks in the SFP, wet drag testing was performed on these cells using a dummy bundle with a smaller cross-sectional area than the test gauge used in the dry drag testing. This restriction limited the potential channel distortion of the fuel assembly stored in the cell and thus the need for additional clearance. Channel distortion is the process by which the fuel channel bows and bulges due to operation in the reactor core. Boral deformation is caused by the interaction between water and Boral. Since all 15 cells marked “DO NOT USE” failed dry drag test prior to exposure to water, the applicant stated that it is not plausible that the drag test failures were caused by Boral deformation.

The staff finds the applicant’s response acceptable because the applicant provided further clarification to the conclusion that the 15 cells marked as “DO NOT USE” did not suffer from Boral deformation. The staff’s concern described in RAI 2.2.5-3 is resolved.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which states that the operating experience of AMPs, including past corrective actions resulting in program enhancements or additional programs, should be considered. A past failure would not necessarily invalidate an AMP because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. This information can show where an existing program has succeeded and where it has failed (if at all) in intercepting aging degradation in a timely manner. This information should provide objective evidence to support the conclusion that the effects of aging will be adequately managed so that the SC intended function(s) will be maintained during the period of extended operation.

During its review, the staff found no operating experience to indicate that the applicant’s program would not be effective in adequately managing aging effects during the period of extended operation. Based on its review of the application and the applicant’s responses to RAIs 2.2.5-1, 2.2.5-2, and 2.2.5-3, the staff finds that operating experience related to the applicant’s program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the “operating experience” program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.2.5 provides the UFSAR supplement for the Boral Monitoring Program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.3-2. In response to RAIs 2.2.5-1, 2.2.5-2, and 2.2.5-3, the applicant revised the UFSAR supplement to include inspection and testing of an SFP test coupon prior to entering the period of extended operation and another test coupon within the first 10 years of entering the period of extended operation. The staff also notes that the applicant committed (Commitment No. 44) to enhance the existing Boral Monitoring Program prior to entering the period of extended operation for managing aging of applicable components. The staff determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its technical review of the applicant's amended Boral Monitoring Program, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.6 Small-Bore Class 1 Piping Inspection

Summary of Technical Information in the Application. LRA Section B.2.2.6 describes the new Small-Bore Class 1 Piping Inspection Program as plant-specific. The applicant stated that the Small-Bore Class 1 Piping Inspection Program is a new program that will manage the aging effect of cracking in small-bore (greater than or equal to nominal pipe size (NPS) 1 and less than NPS 4) Class 1 piping through the use of a combination of volumetric examinations and visual inspections. The applicant further stated that this new program is comprised of the existing ASME Section XI ISI (risk informed-inservice inspection (RI-ISI)) program that performs volumetric and visual examinations for selected Class 1 small-bore butt welds and other selected small-bore socket welds, and a 100 percent inspection of all accessible Class 1 socket welds in the recirculation system using volumetric or other industry-approved techniques.

Staff Evaluation. The staff reviewed program elements one through six of the applicant's program against the acceptance criteria for the corresponding elements as stated in SRP-LR Section A.1.2.3. The staff's review focused on how the applicant's program manages aging effects through the effective incorporation of these program elements. The staff's evaluation of each of these elements follows.

Scope of the Program. LRA Section B.2.2.6 states that the scope of the Small-Bore Class 1 Piping Inspection Program will include a 100 percent inspection of the accessible Class 1 socket welds in the recirculation system, as well as ongoing ASME Section XI ISI (RI-ISI) volumetric and visual examinations for selected Class 1 small-bore butt welds and other selected small-bore socket welds. The applicant further stated that the selected inspections include locations that are susceptible to cracking and that the program will include measures to verify that unacceptable cracking indications are not occurring in Class 1 small-bore piping.

The staff reviewed the applicant's "scope of the program" program element against the criteria in SRP-LR Section A.1.2.3.1, which states the specific program necessary for license renewal should be identified and the scope of the program should include the specific SCs of which the program manages the aging. The staff finds this element of the applicant's Small-Bore Class 1 Piping Inspection Program acceptable because the components to be managed by this program are clearly identified.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1 and, therefore, the staff finds it acceptable.

Preventive Actions. LRA Section B.2.2.6 states the Small-Bore Class 1 Piping Inspection Program is a condition monitoring program and does not include activities for preventing or mitigating aging degradation, therefore, no guidance is provided on preventive or mitigative activities.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which states that for condition or performance monitoring programs, they do not rely on preventive actions and thus, additional information regarding this element does not need to be provided. The staff finds the applicant's determination that no guidance for mitigative or preventive activities is required is acceptable because the applicant's Small-Bore Class 1 Piping Inspection Program is a condition monitoring program where small-bore Class 1 piping welds will be subjected to various inspection methods including volumetric inspection.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2 and, therefore, the staff finds it acceptable.

Parameters Monitored or Inspected. LRA Section B.2.2.6 states that volumetric examinations, or other approved inspection techniques, will inspect 100 percent of all the accessible Class 1 socket welds of the recirculation system to identify degrading welds, and other selected accessible socket welds and small-bore butt welds will be inspected to detect cracking caused by SCC, and thermal and mechanical loading. LRA Section B.2.2.6 further states that the aspects of program inspection techniques included in the RI-ISI program are based on the EPRI RI-ISI Topical Report, EPRI TR-112657, and ASME Code Case N-578-1; the inspections include locations that are the most susceptible to cracking.

The staff reviewed the applicant's "parameters monitored or inspected" program element against the criteria in SRP-LR Section A.1.2.3.3, which states that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular SC intended function(s) and for a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects.

The staff finds the applicant's "parameters monitored or inspected" program element acceptable because the program was developed to detect cracking due to SCC and thermal and mechanical loading of small-bore Class 1 piping, and volumetric inspection or other approved inspection techniques will be implemented to detect cracks in small-bore piping including full penetration welds and socket welds.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3 and, therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.2.2.6 states that the Small-Bore Class 1 Piping Inspection Program detects aging effects before there is a loss of the SC intended functions, where the aspects of program inspection techniques are appropriate for detecting degrading welds caused by cracking due to SCC and thermal and mechanical loading. LRA Section B.2.2.6 further states all accessible Class 1 recirculation system small-bore socket welds are inspected for degraded conditions, as well as other selected small-bore socket and butt welds, as directed by the RI-ISI program requirements, where selected "high" risk and "medium" risk weld locations will be examined to detect cracking.

The staff reviewed the applicant's "detection of aging effects" program element against the criteria in SRP-LR Section A.1.2.3.4, which states that:

(1) Detection of aging effects should occur before there is a loss of the SC intended function(s). The parameters to be monitored or inspected should be appropriate to ensure that the SC intended function(s) will be adequately maintained for license renewal under all CLB design conditions. This includes aspects such as method or technique (e.g., visual, volumetric, surface inspection), frequency, sample size, data collection and timing of new/one-time inspections to ensure timely detection of aging effects. Provide information that links the parameters to be monitored or inspected to the aging effects being managed.

(2) Nuclear power plants are licensed based on redundancy, diversity, and defense-in-depth principles. A degraded or failed component reduces the reliability of the system, challenges safety systems, and contributes to plant risk. Thus, the effects of aging on a structure or component should be managed to ensure its availability to perform its intended function(s) as designed when called upon. In this way, all system level intended function(s), including redundancy, diversity, and defense-in-depth consistent with the plant's CLB, would be maintained for license renewal. A program based solely on detecting SC failure should not be considered as an effective AMP for license renewal.

(3) This program element describes "when," "where," and "how" program data are collected (i.e., all aspects of activities to collect data as part of the program).

(4) The method or technique and frequency may be linked to plant-specific or industry-wide operating experience. Provide justification, including codes and standards referenced, that the technique and frequency are adequate to detect the aging effects before a loss of SC intended function. A program based solely on detecting SC failures is not considered an effective AMP.

(5) When sampling is used to inspect a group of SCs, provide the basis for the inspection population and sample size. The inspection population should be based on such aspects of the SCs as a similarity of materials of construction, fabrication, procurement, design, installation, operating environment, or aging effects. The sample size should be based on such aspects of the SCs as the specific aging effect, location, existing technical information, system and structure design, materials of construction, service environment, or previous failure history. The samples should be biased toward locations most susceptible to the specific aging effect of concern in the period of extended operation. Provisions should also be included on expanding the sample size when degradation is detected in the initial sample.

In the "detection of aging effects" program element, the applicant stated that:

(1) Volumetric examination techniques will detect cracking before the Class 1 small-bore welds leak or fail thus preserving the piping intended function consistent with the CLB of the plant.

(2) Program data will be collected through the applicant's ISI program which is augmented by the Small-Bore Class 1 Piping Inspection Program.

(3) Sampling and population size is based on 100 percent of accessible socket welds in the recirculation system and selected “high” and “medium” risk socket and butt welds based on established risk-informed methods for other locations.

The staff noted that the applicant plans to inspect 100 percent of the accessible Class 1 socket welds in the recirculation system. However, the weld population was not provided. It was not clear to the staff what percentage of ASME Code Class 1 socket welds will be inspected prior to the period of extended operation. In addition, the staff also noted that the applicant’s program only addresses Class 1 small-bore socket welds but did not adequately address volumetric examination of full penetration welds. Specifically, the applicant stated in its risk informed inservice inspection (RI-ISI) program that Class 1 small-bore full penetration welds were included in the population. However, the staff noted that based on its current RI-ISI program plan (ISI Program Plan – Third 10-Year Inspection Interval, December 12, 2007, ADAMS Accession No. ML0735403840), Class 1 small-bore full penetration welds will not be subject to volumetric examinations. In addition, the staff noted that the RI-ISI program is an approved relief request that is valid only for the current 10-year ISI interval. This relief request cannot be assumed to be approved in future ISI intervals. By letter dated December 9, 2010, the staff issued RAI B.2.2.6-01 requesting that the applicant:

(a) Provide the total population of ASME Code Class 1 socket welds and full penetration welds at Hope Creek.

(b) Explain and justify how the sampling methodology used by the RI-ISI program is appropriate and demonstrates adequate aging management of small-bore piping that is in scope for License Renewal, since no full-penetration welds were identified per the RI-ISI program.

(c) In lieu of the justification above, provide a sampling methodology for small bore full-penetration welds and socket welds consistent with the staff’s position on adequate sampling, described above.

(d) Clarify and justify the inspections and sampling methodology for the small bore piping in the recirculation system since there is plant-specific operating experience of cracking.

In its response dated December 15, 2010, the applicant provided supplemental information to its Small-Bore Class 1 Piping Inspection Program. Regarding Part (a) of RAI B.2.2.6-01, the applicant provided its Class 1 weld populations and stated that there are 250 socket welds and 51 full penetration welds. Based on its review, the staff finds the applicant’s response to Part (a) of RAI B.2.2.6-01 acceptable because the subject weld populations were provided.

Regarding Parts (b) and (c) of RAI B.2.2.6-01, the applicant stated that no small-bore full penetration welds were identified for inspection per the current RI-ISI program. The applicant stated that it will include small-bore full penetration welds in its Small-Bore Class 1 Piping Inspection Program. The applicant also provided inspection sampling of both socket welds and full penetration welds. Specifically, 25 full penetration welds (out of a population of 51 welds) and 25 socket welds (out of a population of 250 welds) will be inspected using a sampling methodology to select the most susceptible and risk-significant welds. The inspections will be performed within the 6-year period prior to the period of extended operation. The applicant has subsequently revised program elements 1, 3, and 4 to delete inspection of 100 percent of all the accessible Class 1 socket welds of the recirculation system and include inspection of 25 Class 1 small-bore socket welds and 25 Class 1 small-bore butt welds based on a sample methodology to select the most susceptible and risk-significant welds for inspection.

The staff noted that the inspection sampling of both socket welds and full penetration welds is consistent with the sampling guidance, which is 10 percent of each weld type, in the “detection of aging effects” program element of GALL AMP XI.M35 and, therefore, the staff finds it acceptable. The staff finds the applicant’s inspection schedule is consistent with the recommendations in the “detection of aging effects” program element of GALL AMP XI.M35 for timely implementation of the small-bore piping inspections and is, therefore, acceptable.

Regarding Part (d) of RAI B.2.2.6-01, the applicant stated that it experienced socket weld fatigue failures in the past in its recirculation system and has made design changes to address the vibration source as well as piping changes to reduce suseptiblity of vibration induced fatigue cracking. The applicant further stated that socket weld inspections would focus on the recirculation system as it represents some of the most susceptible and risk-significant socket welds. The staff finds the applicant’s proposal acceptable because the applicant’s inspection methodology will select the most susceptible and risk-significant socket welds.

Based on its review, the staff finds the applicant’s response to RAI B.2.2.6-01 acceptable because the applicant’s program includes: (1) consistency with the recommendations of GALL AMP XI.M35, (2) volumetric examinations of both socket welds and full penetration welds, (3) sampling of 10 percent or more of the weld populations for each weld type, (4) inspection selection of the most susceptible and risk-significant welds, and (5) timely implementation of the inspections. The staff’s concern described in RAI B.2.2.6-01 is resolved.

The staff confirmed that the “detection of aging effects” program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4 and, therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.2.2.6 states that the process for selecting inspection locations is based upon risk-significant components and structures. EPRI TR-112657 and ASME Code Case N-578-1 provide a robust selection process and inspection schedule and are founded on actual service experience with nuclear plant piping failure data. LRA Section B.2.2.6 further states that the frequency of the inspections will detect cracking and age-related degradation prior to loss of intended function, based on industry and plant-specific operating experience; a risk informed inspection schedule directs appropriate inspections to be performed on a timely basis and results of the inspections are evaluated in accordance with station corrective action procedures, which direct additional inspections as required.

The staff reviewed the applicant’s “monitoring and trending” program element against the criteria in SRP-LR Section A.1.2.3.5, which states that monitoring and trending activities should be described, and they should provide predictability of the extent of degradation and thus effect timely corrective or mitigative actions; plant-specific and/or industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency. SRP-LR Section A.1.2.3.5 also states that this program element describes “how” the data collected are evaluated and may also include trending for a forward look.

The staff finds the applicant’s “monitoring and trending” program element acceptable because inspection frequency is based on industry standard methods and piping failure data and results of inspections will be evaluated in a timely manner such that appropriate corrective actions and additional inspections will be scheduled through the station corrective action program.

The staff confirmed that the "monitoring and trending" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.5 and, therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.2.2.6 states that examinations that reveal flaws or relevant indications exceeding acceptance criteria may be acceptable by supplemental examinations, corrective measures, repair or replacement activities, or analytical evaluations in accordance with ASME Code Case N-578-1. LRA Section B.2.2.6 also states that the alternative criteria for additional examinations contained in ASME Code Case N-578-1 provide more guidance for examination method and categorization for parts to be examined, and the supplemental inspections performed on accessible recirculation system piping will be evaluated, reviewed, and dispositioned consistent with ASME Code Section XI requirements.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which states that the acceptance criteria of the program and its basis should be described, and the acceptance criteria, against which the need for corrective actions will be evaluated, should ensure that the SC intended function(s) are maintained under all CLB design conditions during the period of extended operation. The program should include a methodology for analyzing the results against applicable acceptance criteria. SRP-LR Section A.1.2.3.6 also states that acceptance criteria could be specific numerical values, or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria to ensure that the SC intended function(s) will be maintained under all CLB design conditions.

The staff finds the applicant's "acceptance criteria" program element acceptable because specific acceptance criteria are cited which are in accordance with ASME Code Section XI requirements such that the piping intended functions will be maintained during the period of extended operation.

The staff confirmed that the "acceptance criteria" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.6 and, therefore, the staff finds it acceptable.

Operating Experience. LRA Section B.2.2.6 summarizes operating experience related to the Small-Bore Class 1 Piping Inspection Program. The applicant stated that the effects of aging are effectively managed through objective evidence that shows that aging effects and mechanisms are being adequately managed. The applicant provided numerous examples of cracking in ASME Code Class 1 small-bore piping. The staff noted that in each case, the applicant provided corrective actions to repair the cracks or replace the degraded piping with a modified design.

The staff reviewed this information against the criteria in SRP-LR Section A.1.2.3.10, which states that a past failure would not necessarily invalidate an AMP because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. As a result of numerous cracking incidences, the applicant developed this plant-specific AMP in accordance with the recommendations in GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping," where the applicant has scheduled additional volumetric examinations of ASME Code Class 1 small-bore piping consistent with ASME Code Section XI, Subsection IWB.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its review of the application, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the detrimental effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking appropriate corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.2.6, as amended by letter dated December 15, 2010, provides the UFSAR supplement for the Small-Bore Class 1 Piping Inspection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.1-2.

The UFSAR supplement specifically states:

> The Small-Bore Class 1 Piping Inspection program is a new program that will manage the aging effect of cracking in small-bore (greater than or equal to NPS 1 and less than NPS 4) Class 1 piping through the use of a combination of volumetric examinations and visual inspections. This new program is comprised of the existing ASME Section XI ISI (Risk Informed Inservice Inspection, RI-ISI) program that performs volumetric and visual examinations for selected Class 1 small-bore butt welds and other selected small-bore socket welds, and supplemental inspections consisting of 25 Class 1 small-bore socket welds and 25 Class 1 small-bore butt welds using volumetric or other industry approved techniques. The RI-ISI program provides a robust inspection selection process and is based upon the susceptibility to degradation and the consequences of a piping failure, which is founded on actual service experience with nuclear plant piping failure data. The RI-ISI program requires volumetric and VT-2 examinations on a frequency and number determined by ASME Code Case N-578-1 and the Hope Creek ISI Program Plan. These ongoing inspections combined with supplemental inspections consisting of 25 Class 1 small-bore socket welds and 25 Class 1 small-bore butt welds using volumetric or other industry approved techniques and based on a sample methodology to select the most susceptible and risk-significant welds for inspection will be effective in identifying any age related or underlying deficiencies. Any deficiencies identified are evaluated under the corrective action program.
>
> The Small-Bore Class 1 Piping Inspection program will effectively manage the aging effect of cracking in small-bore (greater than or equal to NPS 1 and less than NPS 4) Class 1 piping by identifying and evaluating cracking prior to loss of intended function.
>
> This new program will be implemented prior to the period of extended operation, with the supplemental inspections performed within the six year period prior to the period of extended operation.

The staff also notes that the applicant committed (Commitment No. 45) to implement the new Small-Bore Class 1 Piping Inspection Program prior to entering the period of extended operation, with the supplemental inspections performed within the 6-year period prior to the period of extended operation for managing aging of applicable components.

The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its technical review of the applicant's Small-Bore Class 1 Piping Inspection Program, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) 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 reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.4 Quality Assurance Program Attributes Integral to Aging Management Programs

3.0.4.1 Summary of Technical Information in Application

In Appendix A, "Final Safety Analysis Report Supplement," Section A.1.5, "Quality Assurance Program and Administrative Controls," and Appendix B, "Aging Management Programs," Section B.1.3, "Quality Assurance Program and Administrative Controls," of the LRA, the applicant described the elements of corrective actions, confirmation process, and administrative controls that are applied to the AMPs for both safety-related and nonsafety-related components. The HCGS quality assurance program (QAP) is used, which includes the elements of corrective actions, confirmation process, and administrative controls.

Corrective actions, confirmation process, and administrative controls are applied in accordance with the QAP regardless of the safety classification of the components. LRA Appendix A, Section A.1.5 and Appendix B, Section B.1.3 state that the QAP implements the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and is consistent with the SRP-LR, Revision 1.

3.0.4.2 Staff Evaluation

Pursuant to 10 CFR 54.21(a)(3), an applicant is required to demonstrate that the effects of aging on SCs subject to an AMR will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation. The SRP-LR, Branch Technical Position RLSB-1, "Aging Management Review - Generic," describes 10 attributes of an acceptable AMP. Three of these ten attributes are associated with the QA activities of corrective action, confirmation process, and administrative controls.

Table A.1-1, "Elements of an Aging Management Program for License Renewal," of SRP-LR, Branch Technical Position RLSB-1 provides the following description of these quality attributes:

- Attribute No. 7 - Corrective Actions, including root cause determination and prevention of recurrence, should be timely.
- Attribute No. 8 - Confirmation Process, which should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
- Attribute No. 9 - Administrative Controls, which should provide a formal review and approval process.

The SRP-LR, Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs," states that those aspects of the AMP that affect quality of safety-related SSCs are subject to the QA requirements of 10 CFR Part 50, Appendix B. Additionally, for nonsafety-related SCs subject to an AMR, the applicant's existing 10 CFR Part 50, Appendix B, QAP may be used to address the elements of corrective action, confirmation process, and administrative control.

Branch Technical Position IQMB-1 provides the following guidance with regard to the QA attributes of AMPs:

> Safety-related SCs are subject to Appendix B to 10 CFR Part 50 requirements which are adequate to address all quality related aspects of an AMP consistent with the CLB of the facility for the period of extended operation. For nonsafety-related SCs that are subject to an AMR for license renewal, an applicant has an option to expand the scope of its Appendix B to 10 CFR Part 50 program to include these SCs to address corrective action, confirmation process, and administrative control for aging management during the period of extended operation. In this case, the applicant should document such a commitment in the Final Safety Analysis Report supplement in accordance with 10 CFR 54.21(d).

The staff reviewed the applicant's AMPs described in LRA Appendix A and Appendix B, and the associated implementing procedures. The purpose of this review was to ensure that the QA attributes (corrective action, confirmation process, and administrative controls) were consistent with the staff's guidance described in Branch Technical Position IQMB-1.

Based on its review, the staff finds that the descriptions of the AMPs and their associated quality attributes provided in LRA Appendix A, Section A.1.5 and Appendix B, Section B.1.3 are consistent with the staff's position regarding QA for aging management.

3.0.5 Conclusion

On the basis of its review, the staff finds that the descriptions and applicability of the plant-specific AMPs and their associated quality attributes provided in LRA Appendix A, Section A.1.5 and Appendix B, Section B.1.3 are consistent with the staff's position regarding QA for aging management. The staff concludes that the QA attributes (corrective action, confirmation process, and administrative control) of the applicant's AMPs are consistent with 10 CFR 54.21(a)(3).

3.1 Aging Management of Reactor Vessel, Internals, and Reactor Coolant Systems

This section of the SER documents the staff's review of the applicant's AMR results for the RCS components and component groups of the following:

- Nuclear Boiler Instrumentation
- Reactor Internals
- Reactor Pressure Vessel
- Reactor Recirculation System

3.1.1 Summary of Technical Information in the Application

LRA Section 3.1 provides AMR results for the RCS, reactor vessel, and reactor vessel internals (RVI). LRA Table 3.1.1, "Summary of Aging Management Evaluations for the Reactor Vessel, Internals and Reactor Coolant System," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the RCS, reactor vessel, and RVI components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included issue reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.1.2 Staff Evaluation

The staff reviewed LRA Section 3.1 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the RCS, reactor vessel, and RVI components within the scope of license renewal and 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, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit of AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to verify the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.1.2.1 and 3.1.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.1.2.3.

For components which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.1-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.1 and addressed in the GALL Report.

Table 3.1-1 Staff Evaluation for Reactor Vessel, Reactor Vessel Internals, and Reactor Coolant System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel pressure vessel support skirt and attachment welds (3.1.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (See SER Section 3.1.2.2.1)
Steel; stainless steel; steel with nickel-alloy or stainless steel cladding; nickel-alloy reactor vessel components: flanges; nozzles; penetrations; safe ends; thermal sleeves; vessel shells, heads, and welds (3.1.1-2)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	TLAA	Fatigue is a TLAA (See SER Section 3.1.2.2.1)
Steel; stainless steel; steel with nickel-alloy or stainless steel cladding; nickel-alloy reactor coolant pressure boundary piping, piping components, and piping elements exposed to reactor coolant (3.1.1-3)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	TLAA	Fatigue is a TLAA (See SER Section 3.1.2.2.1)
Steel pump and valve closure bolting (3.1.1-4)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) check Code limits for allowable cycles (less than 7,000 cycles) of thermal stress range	Yes	TLAA	Fatigue is a TLAA (See SER Section 3.1.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel-alloy RVI components (3.1.1-5)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (See SER Section 3.1.2.2.1)
Nickel-alloy tubes and sleeves in a reactor coolant and secondary feedwater/steam environment (3.1.1-6)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.1)
Steel and stainless steel reactor coolant pressure boundary closure bolting, head closure studs, support skirts and attachment welds, pressurizer relief tank components, steam generator components, piping and components external surfaces and bolting (3.1.1-7)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.1)
Steel; stainless steel; and nickel-alloy reactor coolant pressure boundary piping, piping components, piping elements; flanges; nozzles and safe ends; pressurizer vessel shell heads and welds; heater sheaths and sleeves; penetrations; and thermal sleeves (3.1.1-8)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel; stainless steel; steel with nickel-alloy or stainless steel cladding; nickel-alloy reactor vessel components: flanges; nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads, and welds (3.1.1-9)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.1)
Steel; stainless steel; steel with nickel-alloy or stainless steel cladding; nickel-alloy steam generator components (flanges; penetrations; nozzles; safe ends, lower heads, and welds) (3.1.1-10)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.1)
Steel top head enclosure (without cladding) top head nozzles (vent, top head spray or RCIC, and spare) exposed to reactor coolant (3.1.1-11)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.1.2.2.2)
Steel steam generator shell assembly exposed to secondary feedwater and steam (3.1.1-12)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.2)
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-13)	Loss of material due to general (steel only), pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.1.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, nickel-alloy, and steel with nickel-alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads, and welds (3.1.1-14)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.1.2.2.2)
Stainless steel; steel with nickel-alloy or stainless steel cladding; and nickel-alloy reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-15)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.1.2.2.2)
Steel steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam (3.1.1-16)	Loss of material due to general, pitting and crevice corrosion	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry and, for Westinghouse Model 44 and 51 S/G, if general and pitting corrosion of the shell is known to exist, additional inspection procedures are to be developed.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.2)
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds (3.1.1-17)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, evaluated in accordance with 10 CFR 50, Appendix G, and RG 1.99. The applicant may choose to demonstrate that the materials of the nozzles are not controlling for the TLAA evaluations.	Yes	TLAA	Loss of fracture toughness is a TLAA (See SER Section 3.1.2.2.3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds; safety injection nozzles (3.1.1-18)	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor Vessel Surveillance	Yes	Reactor Vessel Surveillance	Consistent with GALL Report (See SER Section 3.1.2.2.3)
Stainless steel and nickel-alloy top head enclosure vessel flange leak detection line (3.1.1-19)	Cracking due to SCC and IGSCC	A plant-specific AMP is to be evaluated.	Yes	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD; and Water Chemistry	Consistent with GALL Report (See SER Section 3.1.2.2.4)
Stainless steel isolation condenser components exposed to reactor coolant (3.1.1-20)	Cracking due to SCC and IGSCC	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and plant-specific verification program	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.1.2.2.4)
Reactor vessel shell fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process (3.1.1-21)	Crack growth due to cyclic loading	TLAA	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.5)
Stainless steel and nickel-alloy RVI components exposed to reactor coolant and neutron flux (3.1.1-22)	Loss of fracture toughness due to neutron irradiation embrittlement, void swelling	UFSAR supplement commitment to: (1) participate in industry RVI aging programs, (2) implement applicable results, and (3) submit for NRC approval, > 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.6)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel reactor vessel closure head flange leak detection line and bottom-mounted instrument guide tubes (3.1.1-23)	Cracking due to SCC	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.7)
Class 1 CASS piping, piping components, and piping elements exposed to reactor coolant (3.1.1-24)	Cracking due to SCC	Water Chemistry and, for CASS components that do not meet the NUREG-0313 guidelines, a plant-specific AMP	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.7)
Stainless steel jet pump sensing line (3.1.1-25)	Cracking due to cyclic loading	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.1.2.2.8)
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-26)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD) and plant-specific verification program	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.1.2.2.8)
Stainless steel and nickel-alloy RVI screws, bolts, tie rods, and hold down springs (3.1.1-27)	Loss of preload due to stress relaxation	UFSAR supplement commitment to: (1) participate in industry RVI aging programs, (2) implement applicable results, and (3) submit for NRC approval, > 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.9)
Steel steam generator feedwater impingement plate and support exposed to secondary feedwater (3.1.1-28)	Loss of material due to erosion	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.10)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel steam dryers exposed to reactor coolant (3.1.1-29)	Cracking due to flow-induced vibration	A plant-specific AMP is to be evaluated.	Yes	BWR Vessel Internals	Consistent with GALL Report (See SER Section 3.1.2.2.11)
Stainless steel RVI components (e.g., upper internals assembly, rod cluster control assembly (RCCA) guide tube assemblies, baffle/former assembly, lower internal assembly, shroud assemblies, plenum cover and plenum cylinder, upper grid assembly, control rod guide tube (CRGT) assembly, core support shield assembly, core barrel assembly, lower grid assembly, flow distributor assembly, thermal shield, instrumentation support structures) (3.1.1-30)	Cracking due to SCC and irradiation-assisted stress-corrosion cracking (IASCC)	Water Chemistry and UFSAR supplement commitment to: (1) participate in industry RVI aging programs, (2) implement applicable results, and (3) submit for NRC approval, > 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.12)
Nickel alloy and steel with nickel-alloy cladding piping, piping component, piping elements, penetrations, nozzles, safe ends, and welds (other than reactor vessel head); pressurizer heater sheaths, sleeves, diaphragm plate, manways and flanges; core support pads/core guide lugs (3.1.1-31)	Cracking due to primary water stress-corrosion cracking (PWSCC)	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and UFSAR supplement commitment to implement applicable plant commitments to: (1) NRC Orders, Bulletins, and GLs associated with nickel alloys and (2) staff-accepted industry guidelines.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.13)
Steel steam generator feedwater inlet ring and supports (3.1.1-32)	Wall thinning due to flow-accelerated corrosion	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.14)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel-alloy RVI components (3.1.1-33)	Changes in dimensions due to void swelling	UFSAR supplement commitment to: (1) participate in industry RVI aging programs, (2) implement applicable results, and (3) submit for NRC approval, > 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.15)
Stainless steel and nickel-alloy reactor CRD head penetration pressure housings (3.1.1-34)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and for nickel alloy, comply with applicable NRC Orders and provide a commitment in the UFSAR supplement to implement applicable: (1) Bulletins and GLs and (2) staff-accepted industry guidelines.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.16)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel with stainless steel or nickel-alloy cladding primary side components; steam generator upper and lower heads, tubesheets, and tube-to-tube sheet welds (3.1.1-35)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and for nickel alloy, comply with applicable NRC Orders and provide a commitment in the UFSAR supplement to implement applicable: (1) Bulletins and GLs and (2) staff-accepted industry guidelines.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.16)
Nickel-alloy, stainless steel pressurizer spray head (3.1.1-36)	Cracking due to SCC and PWSCC	Water Chemistry and One-Time Inspection and for nickel-alloy welded spray heads, comply with applicable NRC Orders and provide a commitment in the UFSAR supplement to implement applicable: (1) Bulletins and GLs and (2) staff-accepted industry guidelines.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.16)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel-alloy RVI components (e.g., upper internals assembly, RCCA guide tube assemblies, lower internal assembly, control element assembly (CEA) shroud assemblies, core shroud assembly, core support shield assembly, core barrel assembly, lower grid assembly, flow distributor assembly) (3.1.1-37)	Cracking due to SCC, PWSCC, and IASCC	Water Chemistry and UFSAR supplement commitment to: (1) participate in industry RVI aging programs, (2) implement applicable results, and (3) submit for NRC approval, > 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.1.2.2.16)
Steel (with or without stainless steel cladding) CRD return line nozzles exposed to reactor coolant (3.1.1-38)	Cracking due to cyclic loading	BWR Control Rod Drive Return Line Nozzle	No	BWR Control Rod Drive Return Line Nozzle	Consistent with GALL Report
Steel (with or without stainless steel cladding) feedwater nozzles exposed to reactor coolant (3.1.1-39)	Cracking due to cyclic loading	BWR Feedwater Nozzle	No	BWR Feedwater Nozzle	Consistent with GALL Report
Stainless steel and nickel-alloy penetrations for CRD stub tubes instrumentation, jet pump instrumentation, standby liquid control, flux monitor, and drain line exposed to reactor coolant (3.1.1-40)	Cracking due to SCC, IGSCC, and cyclic loading	BWR Penetrations and Water Chemistry	No	BWR Penetrations and Water Chemistry	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel-alloy piping, piping components, and piping elements ≥ 4"NPS; nozzle safe ends and associated welds (3.1.1-41)	Cracking due to SCC and IGSCC	BWR Stress Corrosion Cracking and Water Chemistry	No	BWR Stress Corrosion Cracking and Water Chemistry ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with GALL Report (See SER Sections 3.1.2.1.4 and 3.1.2.1.6)
Stainless steel and nickel-alloy vessel shell attachment welds exposed to reactor coolant (3.1.1-42)	Cracking due to SCC and IGSCC	BWR Vessel ID Attachment Welds and Water Chemistry	No	BWR Vessel ID Attachment Welds and Water Chemistry	Consistent with GALL Report
Stainless steel fuel supports and CRD assemblies CRD housing exposed to reactor coolant (3.1.1-43)	Cracking due to SCC and IGSCC	BWR Vessel Internals and Water Chemistry	No	BWR Vessel Internals and Water Chemistry	Consistent with GALL Report
Stainless steel and nickel-alloy core shroud, core plate, core plate bolts, support structure, top guide, core spray lines, spargers, jet pump assemblies, CRD housing, nuclear instrumentation guide tubes (3.1.1-44)	Cracking due to SCC, IGSCC, and IASCC	BWR Vessel Internals and Water Chemistry	No	BWR Vessel Internals and Water Chemistry	Consistent with GALL Report
Steel piping, piping components, and piping elements exposed to reactor coolant (3.1.1-45)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Flow-Accelerated Corrosion	Consistent with GALL Report
Nickel-alloy core shroud and core plate access hole cover (mechanical covers) (3.1.1-46)	Cracking due to SCC, IGSCC, and IASCC	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Not applicable	Not applicable to HCGS (See SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel-alloy RVIs exposed to reactor coolant (3.1.1-47)	Loss of material due to pitting and crevice corrosion	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	BWR Vessel Internals and Water Chemistry	Consistent with GALL Report (See SER Section 3.1.2.1.3)
Steel and stainless steel Class 1 piping, fittings, and branch connections < NPS"4 exposed to reactor coolant (3.1.1-48)	Cracking due to SCC, IGSCC (for stainless steel only), and thermal and mechanical loading	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and One-Time Inspection of ASME Code Class 1 Small-Bore Piping	No	ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD; Water Chemistry; and Small-Bore Class 1 Piping Inspection	Consistent with GALL Report (See SER Section 3.1.2.1.7)
Nickel-alloy core shroud and core plate access hole cover (welded covers) (3.1.1-49)	Cracking due to SCC, IGSCC, and IASCC	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and, for BWRs with a crevice in the access hole covers, augmented inspection using UT or other demonstrated acceptable inspection of the access hole cover welds	No	BWR Vessel Internals and Water Chemistry	Consistent with GALL Report (See SER Section 3.1.2.1.2)
High-strength low-alloy steel top head closure studs and nuts exposed to air with reactor coolant leakage (3.1.1-50)	Cracking due to SCC and IGSCC	Reactor Head Closure Studs	No	Reactor Head Closure Studs	Consistent with GALL Report
CASS jet pump assembly castings; orificed fuel support (3.1.1-51)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement of CASS	No	Thermal Aging and Neutron Irradiation Embrittlement of CASS	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel and stainless steel RCPB pump and valve closure bolting, manway and holding bolting, flange bolting, and closure bolting in high-pressure and high-temperature systems (3.1.1-52)	Cracking due to SCC, loss of material due to wear, loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Structures Monitoring	Consistent with GALL Report (See SER Sections 3.1.2.1.5 and 3.5.2.1.2)
Steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.1.1-53)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS (See SER Section 3.1.2.1.1)
Copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water (3.1.1-54)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS (See SER Section 3.1.2.1.1)
CASS Class 1 pump casings, and valve bodies and bonnets exposed to reactor coolant > 250 °C (> 482 °F) (3.1.1-55)	Loss of fracture toughness due to thermal aging embrittlement	Inservice Inspection (IWB, IWC, and IWD). Thermal aging susceptibility screening is not necessary, ISI requirements are sufficient for managing these aging effects. ASME Code Case N-481 also provides an alternative for pump casings.	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with GALL Report
Copper alloy > 15% zinc (Zn) piping, piping components, and piping elements exposed to closed-cycle cooling water (3.1.1-56)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to HCGS (See SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
CASS Class 1 piping, piping components, and piping elements and CRD pressure housings exposed to reactor coolant > 250 °C (> 482 °F) (3.1.1-57)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Not applicable	Not applicable to HCGS (See SER Sections 3.1.2.1.1 and 3.1.2.2.2)
Steel RCPB external surfaces exposed to air with borated water leakage (3.1.1-58)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Not applicable	Not applicable to BWRs
Steel steam generator steam nozzle and safe end, feedwater nozzle and safe end, auxiliary feedwater (AFW) nozzles and safe ends exposed to secondary feedwater/steam (3.1.1-59)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Not applicable	Not applicable to BWRs
Stainless steel flux thimble tubes (with or without chrome plating) (3.1.1-60)	Loss of material due to wear	Flux Thimble Tube Inspection	No	Not applicable	Not applicable to BWRs
Stainless steel, steel pressurizer integral support exposed to air with metal temperature up to 288 °C (550 °F) (3.1.1-61)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD)	No	Not applicable	Not applicable to BWRs (See SER Section 3.3.2.1.10)
Stainless steel, steel with stainless steel cladding RCS cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant (3.1.1-62)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD)	No	Not applicable	Not applicable to BWRs

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel reactor vessel flange, stainless steel and nickel-alloy RVIs exposed to reactor coolant (e.g., upper and lower internals assembly, CEA shroud assembly, core support barrel, upper grid assembly, core support shield assembly, lower grid assembly) (3.1.1-63)	Loss of material due to wear	Inservice Inspection (IWB, IWC, and IWD)	No	Not applicable	Not applicable to BWRs
Stainless steel and steel with stainless steel or nickel-alloy cladding pressurizer components (3.1.1-64)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	Not applicable	Not applicable to BWRs
Nickel-alloy reactor vessel upper head and CRD penetration nozzles, instrument tubes, head vent pipe (top head), and welds (3.1.1-65)	Cracking due to PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	No	Not applicable	Not applicable to BWRs
Steel steam generator secondary manways and handholds (cover only) exposed to air with leaking secondary side water and/or steam (3.1.1-66)	Loss of material due to erosion	Inservice Inspection (IWB, IWC, and IWD) for Class 2 components	No	Not applicable	Not applicable to BWRs
Steel with stainless steel or nickel-alloy cladding; or stainless steel pressurizer components exposed to reactor coolant (3.1.1-67)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	Not applicable	Not applicable to BWRs

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, steel with stainless steel cladding Class 1 piping, fittings, pump casings, valve bodies, nozzles, safe ends, manways, flanges, CRD housing; pressurizer heater sheaths, sleeves, diaphragm plate; pressurizer relief tank components, RCS cold leg, hot leg, surge line, and spray line piping and fittings (3.1.1-68)	Cracking due to SCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	Not applicable	Not applicable to BWRs
Stainless steel, nickel-alloy safety injection nozzles, safe ends, and associated welds and buttering exposed to reactor coolant (3.1.1-69)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	Not applicable	Not applicable to BWRs
Stainless steel; steel with stainless steel cladding Class 1 piping, fittings, and branch connections < NPS (nominal pipe size) 4" exposed to reactor coolant (3.1.1-70)	Cracking due to SCC, and thermal and mechanical loading	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and One-Time Inspection of ASME Code Class 1 Small-bore Piping	No	Not applicable	Not applicable to BWRs
High-strength low-alloy steel closure head stud assembly exposed to air with reactor coolant leakage (3.1.1-71)	Cracking due to SCC and loss of material due to wear	Reactor Head Closure Studs	No	Not applicable	Not applicable to BWRs
Nickel-alloy steam generator tubes and sleeves exposed to secondary feedwater/steam (3.1.1-72)	Cracking due to outside-diameter stress-corrosion cracking (ODSCC) and intergranular attack, and loss of material due to fretting and wear	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable to BWRs

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel-alloy steam generator tubes, repair sleeves, and tube plugs exposed to reactor coolant (3.1.1-73)	Cracking due to PWSCC	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable to BWRs
Chrome plated steel, stainless steel, nickel-alloy steam generator anti-vibration bars exposed to secondary feedwater/steam (3.1.1-74)	Cracking due to SCC, and loss of material due to crevice corrosion and fretting	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable to BWRs
Nickel-alloy once-through steam generator (OTSG) tubes exposed to secondary feedwater/steam (3.1.1-75)	Denting due to corrosion of carbon steel tube support plate	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable to BWRs
Steel steam generator tube support plate, tube bundle wrapper exposed to secondary feedwater/steam (3.1.1-76)	Loss of material due to erosion, general, pitting, and crevice corrosion and ligament cracking due to corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable to BWRs
Nickel-alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater/steam (3.1.1-77)	Loss of material due to wastage and pitting corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable to BWRs
Steel steam generator tube support lattice bars exposed to secondary feedwater/steam (3.1.1-78)	Wall thinning due to flow-accelerated corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable to BWRs

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel-alloy steam generator tubes exposed to secondary feedwater/steam (3.1.1-79)	Denting due to corrosion of steel tube support plate	Steam Generator Tube Integrity; Water Chemistry and, for plants that could experience denting at the upper support plates, evaluate potential for rapidly propagating cracks and then develop and take corrective actions consistent with NRC Bulletin 88-02.	No	Not applicable	Not applicable to BWRs
CASS RVIs (e.g., upper internals assembly, lower internal assembly, CEA shroud assemblies, control rod guide tube assembly, core support shield assembly, lower grid assembly) (3.1.1-80)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement of CASS	No	Not applicable	Not applicable to BWRs
Nickel alloy or nickel-alloy clad steam generator divider plate exposed to reactor coolant (3.1.1-81)	Cracking due to PWSCC	Water Chemistry	No	Not applicable	Not applicable to BWRs
Stainless steel steam generator primary side divider plate exposed to reactor coolant (3.1.1-82)	Cracking due to SCC	Water Chemistry	No	Not applicable	Not applicable to BWRs
Stainless steel, steel with nickel-alloy or stainless steel cladding, and nickel-alloy RVIs and RCPB components exposed to reactor coolant (3.1.1-83)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Not applicable	Not applicable to BWRs

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel-alloy steam generator components such as, secondary side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater/steam (3.1.1-84)	Cracking due to SCC	Water Chemistry and One-Time Inspection, or Inservice Inspection (IWB, IWC, and IWD)	No	Not applicable	Not applicable to BWRs
Nickel-alloy piping, piping components, and piping elements exposed to air – indoor uncontrolled (external) (3.1.1-85)	None	None	No	None	Consistent with GALL Report
Stainless steel piping, piping components, and piping elements exposed to air – indoor uncontrolled (external); air with borated water leakage; concrete; gas (3.1.1-86)	None	None	No	None	Consistent with GALL Report
Steel piping, piping components, and piping elements in concrete (3.1.1-87)	None	None	No	Not applicable	Not applicable to HCGS (See SER Section 3.1.2.1.1)

The staff's review of the RCS component groups followed several approaches. One approach, documented in SER Section 3.1.2.1, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.1.2.2, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.1.2.3, discusses the staff's review of AMR results for components the applicant indicated are not consistent with or not addressed in the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the RCS components is documented in SER Section 3.0.3.

3.1.2.1 AMR Results That Are Consistent with the GALL Report

LRA Section 3.1.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the reactor vessel, RVIs, and RCS components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity Program
- BWR Control Rod Drive Return Line Nozzle
- BWR Feedwater Nozzle
- BWR Penetrations
- BWR Stress Corrosion Cracking
- BWR Vessel ID Attachment Welds
- BWR Vessel Internals
- External Surfaces Monitoring
- One-Time Inspection Program
- Periodic Inspection
- Reactor Head Closure Studs
- Reactor Vessel Surveillance
- Small-Bore Class 1 Piping Inspection
- Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)
- TLAA
- Water Chemistry Program

LRA Tables 3.1.2-1 through 3.1.2-4 summarize the results of AMRs for the RCS, reactor vessel, and RVI components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant had claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item describing how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with Notes A through E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff reviewed these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff reviewed these line items to verify consistency with the GALL Report and that it had reviewed and accepted the identified exceptions to the GALL Report AMPs. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component under review. The staff reviewed these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component applied to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff reviewed these line items to verify consistency with the GALL Report. The staff confirmed whether the AMR line item of the different component was applicable to the component under review and whether the exceptions to the GALL Report AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff reviewed these line items to verify consistency with the GALL Report and determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, it did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

The staff reviewed the LRA to confirm that the applicant: (a) provided a brief description of the system, components, materials, and environments; (b) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (c) identified those aging effects for the RCS, reactor vessel, and RVI components that are subject to an AMR.

On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.1.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

3.1.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.1.1, item 3.1.1-46 addresses nickel-alloy core shroud and core plate access hole cover (mechanical covers) exposed to reactor coolant subject cracking due to SCC, IGSCC, and IASCC for this component group. The applicant stated that this line item is not applicable because it has access hole covers that are of a welded design and not a mechanical (bolted) design. The applicant further stated that the access hole covers of a welded design are addressed under item 3.1.1-49. The staff confirmed that the applicant is managing the core shroud and core plate (access hole cover-welded covers) for cracking due to SCC, IGSCC, and IASCC with its BWR Vessel Internals Program and Water Chemistry Program. The staff noted that the applicant is managing the same aging effects that are addressed in item 3.1.1-46. Based on its review, the staff finds the applicant's statement that item 3.1.1-46 is not applicable acceptable because the applicant: (1) addressed aging of these components in item 3.1.1-49 and (2) is managing these components for the same aging effects addressed in item 3.1.1-49.

LRA Table 3.1.1, item 3.1.1-53 addresses steel piping, piping components, and piping elements exposed to closed-cycle cooling water subject to loss of material due to general, pitting and crevice corrosion for this component group. The applicant stated that this line item is not applicable because it has no steel piping, piping components, or piping elements exposed to closed-cycle cooling water in nuclear boiler instrumentation, reactor internals, RPV, and the reactor recirculation system. The staff reviewed the applicant's UFSAR and confirmed that no in-scope steel piping, piping components, and piping elements exposed to closed-cycle cooling water are present in these systems and, therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.1.1, item 3.1.1-54 addresses copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water subject to loss of material due to pitting, crevice, and galvanic corrosion for this component group. The applicant stated that this line item is not applicable because it has no copper alloy piping, piping components, or piping elements exposed to closed-cycle cooling water in nuclear boiler instrumentation, reactor internals, RPV, and the reactor recirculation system. The staff reviewed the applicant's UFSAR and confirmed that no in-scope copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water are present in these systems and, therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.1.1, item 3.1.1-56 addresses copper alloy greater than 15 percent Zn piping, piping components, and piping elements exposed to closed-cycle cooling water subject to loss of material due to selective leaching for this component group. The applicant stated that this line item is not applicable because it has no copper alloy greater than 15 percent Zn piping, piping components, or piping elements exposed to closed-cycle cooling water in nuclear boiler instrumentation, reactor internals, RPV, and the reactor recirculation system. The staff reviewed the applicant's UFSAR and confirmed that no in-scope copper alloy greater than 15 percent Zn piping, piping components, and piping elements exposed to closed-cycle cooling water are present in these systems and, therefore, the staff finds the applicant's determination acceptable.

LRA Tables 3.1.1, item 3.1.1-57 addresses CASS Class 1 piping, piping components, and piping elements and CRD pressure housings exposed to reactor coolant greater than 250 °C (482 °F) subject to loss of fracture toughness due to thermal aging embrittlement for this component group. The applicant stated that this line item is not applicable because with the exception of the Class 1 pump casings and valve bodies, and reactor internals components, there are no other CASS piping, piping components, or piping elements in nuclear boiler instrumentation, reactor internals, RPV, and the reactor recirculation system exposed to reactor coolant greater than 250 °C (482 °F) that require aging management for loss of fracture toughness due to thermal aging embrittlement. The applicant further stated that loss of fracture toughness due to thermal aging embrittlement in CASS Class 1 pump casings and valve bodies is addressed by item 3.1.1-55, and the loss of fracture toughness due to thermal aging and neutron irradiation embrittlement of CASS for the reactor internals components is addressed by item 3.1.1-51. The staff reviewed the applicant's UFSAR and confirmed that no in-scope CASS Class 1 piping, piping components, and piping elements and CRD pressure housings exposed to reactor coolant greater than 250 °C (482 °F) are present in these systems and, therefore, the staff finds the applicant's determination acceptable.

The staff confirmed that for CASS Class 1 pump casings and valve bodies, the applicant is managing loss of fracture toughness due to thermal aging embrittlement, addressed under item 3.1.1-55, with its ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, consistent with the recommendations of the GALL Report. The staff also confirmed that for CASS RVIs, the applicant is managing loss of fracture toughness due to thermal aging and neutron irradiation embrittlement, addressed under item 3.1.1-51, with its Thermal Aging and Neutron Irradiation Embrittlement of CASS Program, consistent with the recommendations of the GALL Report. Based on its review, the staff finds the applicant's proposed program to manage CASS Class 1 pump casings, valve bodies, and RVIs acceptable because it is consistent with the recommendations of the GALL Report.

The applicant further stated that the CASS Class 1 flow restrictor nozzles in the main steam system are not susceptible to thermal embrittlement because the nozzles were cast by a centrifugal casting method using low molybdenum stainless material (SA 351 CF8). The staff noted that the "scope of the program" program element of GALL AMP XI.M12 states the susceptibility to thermal aging embrittlement of CASS components is determined in terms of casting method, molybdenum content, and ferrite content. It further states that all centrifugal cast low-molybdenum steels are not susceptible to thermal aging embrittlement. The staff confirmed that the applicant addressed cracking due to SCC and loss of material due to pitting and crevice corrosion in items 3.1.1-41 and 3.1.1-15, respectively. Based on its review, the staff finds it acceptable that loss of fracture toughness due to thermal embrittlement is not managed for these Class 1 flow elements fabricated from CASS because they were cast by a centrifugal casting method using low molybdenum stainless material, which are not susceptible consistent with the recommendations in GALL AMP XI.M12. Based on its review, the staff finds the applicant's statement that item 3.1.1-57 is not applicable acceptable.

LRA Table 3.1.1, item 3.1.1-87 addresses steel piping, piping components, and piping elements in concrete. The GALL Report recommends that there is no aging effect requiring management (AERM). The applicant stated that this line item is not applicable because it has no steel piping, piping components, and piping elements exposed to concrete in nuclear boiler instrumentation, reactor internals, RPV, and the reactor recirculation system. The staff reviewed the applicant's UFSAR and confirmed that no in-scope steel piping, piping components, and piping elements in concrete are present in the systems and, therefore, the staff finds the applicant's determination acceptable.

3.1.2.1.2 Cracking Due to Stress-Corrosion Cracking, Intergranular Stress-Corrosion Cracking, and Irradiation-Assisted Stress-Corrosion Cracking

LRA Table 3.1.1, item 3.1.1-49 addresses nickel-alloy, welded access hole covers exposed to reactor coolant which are being managed for cracking due to SCC, IGSCC, and IASCC. The LRA credits the BWR Vessel Internals and the Water Chemistry Programs to manage the aging effect. The GALL Report recommends GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and GALL AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited.

For those line items associated with generic note E, GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," recommends using periodic visual examination and leakage testing with augmented inspections of creviced areas along with GALL AMP XI.M2, "Water Chemistry," which recommends monitoring and controlling known detrimental contaminants in accordance with the recommendations of BWRVIP-130 to manage the effects of aging. In its review of components associated with item 3.1.1-49 for which the applicant cited generic note E, the staff noted that the BWR Vessel Internals Program proposes to manage the aging of nickel-alloy, welded access hole covers through the use of EVT-1 to inspect the creviced regions of the welded access hole covers. The staff noted that the EVT-1 inspection is a capable method for detecting fine-scale cracking that is characteristic of IGSCC and IASCC.

The staff's evaluation of the applicant's BWR Vessel Internals Program and Water Chemistry Program are documented in SER Sections 3.0.3.1.7 and 3.0.3.2.1, respectively. The staff noted that the Water Chemistry Program includes controls of chemistry parameters which create an environment to reduce susceptibility to IGSCC.

In its review of the component associated with item 3.1.1-49, the staff finds the applicant's proposal to manage aging using the BWR Vessel Internals Program acceptable because: (1) it follows the guidelines in BWRVIP-180 for EVT-1 inspections for welded access hole covers, which is a proven technique that is capable of detecting the fine-scale cracking associated with IGSCC and IASCC and includes provisions for specific flaw evaluation guidelines to assess any indications of cracking that are detected; and (2) the applicant's use of the Water Chemistry Program creates an environment to reduce susceptibility to IGSCC and is consistent with the recommendations of the GALL Report.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.3 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.1.1, item 3.1.1-47 addresses nickel-alloy and stainless steel RVI components exposed to reactor coolant which are being managed for loss of material due to pitting and crevice corrosion. The LRA credits the BWR Vessel Internals Program and the Water Chemistry Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and GALL AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed. The associated AMR line items cite generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited.

For those line items associated with generic note E, GALL AMP XI.M1 recommends using periodic visual, surface, and/or volumetric examination and leakage testing along with GALL AMP XI.M2, which recommends monitoring and controlling known detrimental contaminants in accordance with the recommendations of BWRVIP-130 to manage the aging of this line item. In its review of components associated with item 3.1.1-47 for which the applicant cited generic note E, the staff noted that the BWR Vessel Internals Program is substituted for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program because it proposes to manage the aging of nickel-alloy and stainless steel RVI components through ISIs according to component-specific BWRVIP documents that include industry-approved inspection procedures and flaw evaluations. The staff noted that the BWRVIP recommended inspections are often more stringent than those inspections specified by ASME Code Section XI, such as the BWRVIP use of EVT-1 or UT, in place of VT-1 or VT-3 from ISI for select components and locations. The staff noted that the applicant’s use of its Water Chemistry Program is consistent with the recommendations of the GALL Report.

The staff’s evaluation of the applicant’s BWR Vessel Internals Program and Water Chemistry Program are documented in SER Sections 3.0.3.1.7 and 3.0.3.2.1, respectively. The staff noted that the Water Chemistry Program includes controls of chemistry parameters which create an environment that is not conducive for loss of material to occur.

In its review of components associated with item 3.1.1-47, the staff finds the applicant’s proposal to manage aging using the BWR Vessel Internals Program and Water Chemistry Program acceptable because: (1) the BWR Vessel Internals Program follows the guidelines recommended by the BWRVIP, which are often more stringent than those inspections specified by ASME Code Section XI, and include specific flaw evaluation and repair recommendations to facilitate post-inspection review; and (2) the applicant’s use of the Water Chemistry Program creates an environment that is not conducive for loss of material to occur, and is consistent with the recommendations of the GALL Report.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.4 Cracking Due to Stress-Corrosion Cracking

LRA Table 3.1.2-3, item 3.1.1-41 addresses nickel-alloy and stainless steel piping components exposed to reactor coolant which are being managed for cracking due to stress-corrosion cracking. The LRA credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M7, “BWR Stress Corrosion Cracking,” and GALL AMP XI.M2, “Water Chemistry,” to ensure that these aging effects are adequately managed. The associated AMR line items cite generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited.

For those line items associated with generic note E, GALL AMP XI.M7 recommends using periodic visual and/or volumetric examination and leakage testing along with GALL AMP XI.M2, which recommends monitoring and controlling known detrimental contaminants in accordance with the recommendations of BWRVIP-130 to manage the aging of this line item. In its review of components associated with item 3.1.1-41 for which the applicant cited generic note E, the staff noted that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is substituted for the BWR Stress Corrosion Cracking Program because it proposes to manage the aging of nickel-alloy and stainless steel RVI components through ISIs according to the ASME Code Section XI and component-specific BWRVIP documents that include industry-approved inspection procedures and flaw evaluations. The staff noted that the BWRVIP recommended inspections are often more stringent than those inspections specified by ASME Code Section XI, such as the use of EVT-1 or UT, in place of VT-1 or VT-3 for select components and locations. The staff also noted that the Water Chemistry Program is consistent with the recommendations of the GALL Report.

The staff's evaluation of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program are documented in SER Sections 3.0.3.1.1 and 3.0.3.2.1, respectively. The staff noted that the components associated with item 3.1.1-41 for which the applicant cited generic note E, include steel with stainless steel cladding, stainless steel, and nickel alloy for nozzles (CRD return, core spray, jet pump instrumentation, recirculation inlet and outlet), penetrations (stub tubes, incore housings), and the reactor vessel bottom head, shell, and shell flange. In its review of components associated with item 3.1.1-41, the staff finds the applicant's proposal to manage aging using the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program acceptable because the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program includes component-specific BWRVIP documents that include industry-approved inspection procedures and flaw evaluations, which require more stringent inspections than those specified by ASME Code Section XI, such as the use of EVT-1 or UT, in place of VT-1 or VT-3 for select components and locations, and the applicant's use of the Water Chemistry Program is consistent with the recommendations of the GALL Report.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.5 Cracking Due to Stress-Corrosion Cracking, Loss of Material Due to Wear, Loss of Preload Due to Thermal Effects, Gasket Creep, and Self-loosening

LRA Table 3.1.1, item 3.1.1-52 addresses steel and stainless steel bolting exposed to high pressure and high temperature systems which are being managed for SCC, loss of material due to wear, and loss of preload due to thermal effects, gasket creep, and self-loosening. The LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program and the Structures Monitoring Program to manage these aging effects. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to ensure that the aging effects are adequately managed. In LRA Table 3.3.2-8 (Cranes & Hoists), Table 3.3.2-13 (Fuel Handling and Storage System), and Table 3.5.2-7 (Primary Containment), the applicant aligned AMR results for carbon, low alloy, and stainless steel bolting exposed to air with item 3.1.1-52. The AMR result lines cite generic note E, indicating that the AMR result is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The AMR result lines also cite plant-specific notes stating that for these combinations of component type, material, and environment, the aging mechanisms of thermal effects and gasket creep are not applicable, but reductions of preload caused by self-loosening due to vibration or joint flexing is assumed potentially to occur.

The staff reviewed the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program and the Structures Monitoring Program, and its evaluations are documented in SER Sections 3.0.3.2.6, and 3.0.3.2.16, respectively.

The staff noted that the applicant's Structures Monitoring Program uses procedures that have incorporated the guidance in EPRI TR-104319 and includes periodic visual inspections for loose nuts, missing bolts, or other signs of loss of preload. The staff finds the applicant's proposed program acceptable to manage aging for these components because it uses visual inspections to detect loss of preload and has incorporated the guidance recommended in GALL AMP XI.M18. The staff noted that bolting in the cranes and hoists system, fuel handling and storage system, and primary containment system are not subjected to high temperatures and finds the applicant's statement that thermal effects and gasket creep are not applicable aging mechanisms for bolting in these systems to be acceptable because exposure to high temperatures is required for these aging mechanisms to occur.

During its review of AMR result lines associated with components for which the GALL Report recommends the Bolting Integrity Program, the staff noted that several other programs were identified to manage aging for bolting in the LRA. The staff issued RAI B.2.1.12-01 requesting that the applicant explain why programs other than the Bolting Integrity Program were credited to manage aging for structural bolting.

In its response, which is evaluated in SER Section 3.0.3.2.4, the applicant added a number of AMR result lines, including lines associated with LRA Table 3.1.1, item 3.1.1-52. The AMR result lines credit the Bolting Integrity Program to manage loss of preload, in addition to the previously credited program, and cite generic note B, indicating that the results are consistent with the GALL Report for component, material, environment, and aging effect, but the AMP takes some exception(s) to the GALL Report.

The staff finds the applicant's proposed combination of programs acceptable to manage aging for these components because: (1) all of the programs include visual inspections of bolting which are capable of detecting loss of preload, (2) the use of the Bolting Integrity Program is consistent with the recommendations in the GALL Report, (3) the inspections performed by the Bolting Integrity Program supplements inspections performed by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems, and (4) the Structures Monitoring Program provides a more comprehensive approach to monitoring aging for these components.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.6 Cracking Due to Stress-Corrosion Cracking and Intergranular Stress-Corrosion Cracking

LRA Table 3.1.1, item 3.1.1-41 addresses stainless steel and nickel-alloy piping, piping components, and piping elements greater than or equal to 4 inches NPS, nozzle safe ends, and associated welds which are being managed for cracking due to SCC and IGSCC. The LRA credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry Programs to manage cracking for stainless steel penetrations and carbon or low alloy steel with stainless steel cladding nozzles; reactor vessel bottom head; upper, upper intermediate, intermediate, lower intermediate, and lower shell sections; and shell flange. The GALL Report recommends GALL AMP XI.M7, "BWR Stress Corrosion Cracking," and GALL AMP XI.M2, "Water Chemistry," to ensure these aging effects are adequately managed. The associated AMR line items cite generic note E, which indicate that the line item is consistent with the GALL Report for the material, environment, and aging effect, but a different AMP is credited.

GALL AMP XI.M7 recommends preventive measures to mitigate the effects of IGSCC, including water chemistry control, reduction of tensile stresses, and proper selection of materials, as well as ISIs and flaw evaluations to monitor for IGSCC and its effects. GALL AMP XI.M2 recommends monitoring and controlling the concentration of contaminates in the water to minimize the occurrence of SCC.

The staff reviewed the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry Programs and its evaluations are documented in SER Sections 3.0.3.1.1 and 3.0.3.2.1, respectively. The staff noted that the applicant's Water Chemistry Program includes monitoring and controlling the concentration of contaminates in the water to minimize cracking. The staff also noted that the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program includes periodic visual, surface, and volumetric examinations and leakage testing of ASME Class 1, 2, and 3 components. The staff further noted that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program has incorporated the guidance from BWRVIP-75, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules," which includes recommendations regarding proper selection of materials and reduction of stresses and is consistent with the recommendations in GALL AMP XI.M7. The staff finds the applicant's proposed programs acceptable to manage aging for these components because the Water Chemistry Program will monitor and control contaminants in the water, and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will perform periodic inspections and leakage testing in accordance with accepted industry guidance.

However, for a CASS ASME Class 1 flow element, LRA Table 3.4.2-4 credits the Water Chemistry Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M7, "BWR Stress Corrosion Cracking," and GALL AMP XI.M2, "Water Chemistry," to ensure these aging effects are adequately managed. The associated AMR line items cite generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effects, but a different AMP is credited. The AMR line items also cite in a plant-specific note that this CASS nozzle (a Class 1 flow element) is not susceptible to thermal embrittlement because it was cast by a centrifugal casting method using low molybdenum stainless steel material (SA 351 CF8).

The staff noted that SA 351 CF8 grade material is not susceptible to thermal embrittlement, but is susceptible to cracking and stress corrosion cracking. To manage cracking due to SCC, the

GALL Report recommends use of both GALL AMP XI.M7 “BWR Stress Corrosion Cracking” and GALL AMP XI.M2, “Water Chemistry.” The applicant only credited one AMP (Water Chemistry). By letter dated August 3, 2010, the staff issued RAI 3.4.2.4-01 requesting that the applicant justify why it did not credit the BWR Stress Corrosion Cracking program for managing the aging effect of cracking due to SCC and IGSCC of this nozzle.

In its response dated August 26, 2010, the applicant stated that the steam flow element consists of an outer carbon steel pipe section, which performs the Class 1 reactor coolant pressure boundary function, and an internal nozzle insert that provides the throttle intended function. The applicant stated that the nozzle insert is made of two sections: an upstream nozzle section made of CASS welded to a downstream section made of carbon steel. The applicant further stated that the CASS portion of the nozzle insert does not meet the applicability criteria of GALL AMP XI.M7. The applicant also stated that water chemistry program would be an effective means to maintain the contaminants below the levels that would promote cracking because the flow element is located in a high steam flow area. The applicant further stated that the carbon content of the CASS portion of the flow element ranges between 0.04 and 0.06 wt. percent and ferrite content varies between 14 and 32 wt. percent. The staff notices that, under the GALL AMP XI.M7 recommendation, a component is resistant to sensitization (i.e., susceptibility to cracking/SCC) if the stainless steel material has a maximum carbon of 0.035 wt. percent and a minimum ferrite of 7.5 percent in weld metal and CASS. Since the CASS carbon content exceeds the GALL Report recommended maximum value of 0.035 percent, the staff reviewed the technical basis document BWRVIP-75-A[2] referenced in GALL AMP XI.M7. BWRVIP-75-A states, in part, that “castings with a carbon content higher than 0.035 percent are generally not considered resistant to sensitization. However, experience has shown that welds joining these castings to resistant piping have performed well and can therefore be included in Category A[3]. If extensive weld repairs were performed, the welds should be included in the Category D population[4].” As documented in the applicant’s e-mail correspondence (ADAMS Accession No. ML102560006), dated September, 9, 2010, the applicant confirmed that the main steam flow element CASS material had not been repaired during the plant operation to date. Thus this main steam flow element CASS material can be regarded as resistant to cracking, in accordance with the BWRVIP-75-A. Therefore, the staff finds the applicant’s use of Water Chemistry and One-Time Inspection programs to mitigate the aging of the Class 1 flow element (nozzle) acceptable because the applicant has selected a material that is resistant to cracking due to SCC, and use of the Water Chemistry and One-Time Inspection Programs is consistent with the GALL Report recommended programs.

The staff concludes, based on the e-mail correspondence (ADAMS Accession No. ML102560006), that the applicant has demonstrated that the effects of aging for these

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[2] EPRI Technical Report 1012621, “BWRVIP-75-A: BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules” Final Report, October 2005

[3] Category A weldments are those with no known cracks that have low probability of experiencing IGSCC because they are made entirely of IGSCC resistant materials or have been solution heat treated after welding (Section 2.1.1 of BWRVIP-75-A).

[4] Category D weldments are those not made with resistant materials (Section 2.4.1 of BWRVIP-75-A).

components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.7 Cracking Due to Stress-Corrosion Cracking, Intergranular Stress-Corrosion Cracking (for Stainless Steel Only), and Thermal and Mechanical Loading

LRA Table 3.1.1, item 3.1.1-48 addresses carbon steel Class 1 piping, fittings, and branch line connections less than 4 inches NPS exposed to steam or treated water (reactor coolant) which are being managed for cracking due to thermal or mechanical loading. This LRA item also addresses: (1) stainless steel Class 1 piping, fittings, and branch line connections less than 4 inches NPS exposed to steam or treated water greater than 140 °F which are being managed for cracking due to SCC and thermal or mechanical loading; and (2) stainless steel Class 1 condensing chambers, flow devices, restricting orifices, thermowells, and valve bodies which are being managed for cracking due to SCC. The LRA credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program; the Water Chemistry Program; and the Small-Bore Class 1 Piping Inspection Program, which is a plant-specific program, to manage the aging effect in the carbon steel or stainless steel Class 1 piping, fittings, and branch line connections. However, for the stainless steel Class 1 condensing chambers, flow devices, restricting orifices, thermowells, and valve bodies, the LRA credits only the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and the Water Chemistry Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD”; GALL AMP XI.M2, “Water Chemistry”; and GALL AMP XI.M35, “One-Time Inspection of ASME Code Class 1 Small-Bore Piping,” to ensure that these aging effects are adequately managed. For the Class 1 piping, fittings, and branch line connections, AMR line items crediting the Small-Bore Class 1 Piping Inspection Program cite generic note E. Also, for the Class 1 condensing chambers, flow devices, restricting orifices, thermowells, and valve bodies, AMR lines crediting the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and the Water Chemistry Program cite generic note E.

For those AMR line items associated with generic note E, GALL AMP XI.M35 recommends using one-time volumetric inspections for cracking, together with the Water Chemistry Program and ongoing ASME Code Section XI ISIs, to manage the aging effect of cracking.

In its review of components associated with item 3.1.1-48 for which the applicant cited generic note E and credited the Small-Bore Class 1 Piping Inspection Program, the staff noted that the credited program proposes to manage the aging of carbon steel or stainless steel Class 1 piping, fittings, and branch line connections less than 4 inches NPS through the use of ongoing visual inspections and volumetric examinations for selected Class 1 small-bore butt welds and other selected small-bore socket welds.

The staff’s evaluation of the applicant’s Small-Bore Class 1 Piping Inspection Program is documented in SER Section 3.0.3.3.6. The staff notes that the applicant’s Small-Bore Class 1 Piping Inspection Program provides ongoing inspections of selected piping welds using a combination of visual inspections and volumetric examinations that are equivalent to those recommended in GALL AMP XI.M35. The staff also notes that the selection criteria for components to be inspected in the Small-Bore Class 1 Piping Inspection Program include consideration of susceptibility to degradation similar to the selection criteria recommended in GALL AMP XI.M35. The staff further notes that the primary difference between the applicant’s Small-Bore Class 1 Piping Inspection Program and GALL AMP XI.M35 is that the applicant’s program provides ongoing inspections and the GALL Report AMP specifies a one-time inspection. The staff finds the applicant's use of its Small-Bore Class 1 Piping Inspection Program in lieu of GALL AMP XI.M35 acceptable because the applicant's program uses appropriate examination techniques and component selection criteria, and provides for examination that occurs more frequently than the one-time examination specified in GALL AMP XI.M35.

In its review of components associated with item 3.1.1-48 where the applicant cited generic note E and credited the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, the staff noted that the credited programs propose to manage the aging of Class 1 condensing chambers, flow devices, restricting orifices, thermowells, and valve bodies using control of water chemistry and ASME Code Section XI-required inspections for these components.

The staff's evaluation of the applicant's ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program and Water Chemistry Program are documented in SER Sections 3.0.3.1.1 and 3.0.3.2.1, respectively. The staff notes that the applicant's Water Chemistry Program provides mitigation for cracking due to SCC in stainless steel components, and the applicant's ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program provides for VT-2 visual examination (system leakage test) of these components in accordance with ASME Code Section XI Examination Category B-P, applicable for all Class 1 pressure boundary components. The staff also notes that the applicant does not credit a volumetric examination of these components comparable to what is recommended in GALL AMP XI.M35. The staff further notes that the material, environment, and aging effect for these components is the same as for the stainless steel Class 1 piping, fittings, and branch line connections less than 4 inches NPS where the applicant does perform a volumetric examination of selected piping welds. The staff notes that Class 1 condensing chambers, flow devices, restricting orifices, thermowells, and valve bodies are less susceptible to cracking due to SCC than stainless steel piping welds in the same environment; and welds associated with Class 1 condensing chambers, flow devices, restricting orifices, thermowells, and valve bodies have susceptibility similar to stainless steel piping welds. The staff further notes that the VT-2 examination of Class 1 condensing chambers, flow devices, restricting orifices, thermowells, and valve bodies provides ongoing confirmation that unacceptable leakage of these components does not occur. Because the applicant is performing volumetric examination of similar components that would provide an indication of whether cracking in the stainless steel Class 1 condensing chambers, flow devices, restricting orifices, thermowells, and valve bodies is an issue and the VT-2 examination provides ongoing confirmation that component pressure boundary integrity is intact, the staff finds it acceptable for the applicant to use the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for aging management of stainless steel Class 1 condensing chambers, flow devices, restricting orifices, thermowells, and valve bodies.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operations, as required by 10 CFR 54.21(a)(3).

3.1.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

LRA Section 3.1.2.2 provides further evaluation of aging management as recommended by the GALL Report for the RCS components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of fracture toughness due to neutron irradiation embrittlement
- cracking due to SCC and IGSCC
- crack growth due to cyclic loading
- loss of fracture toughness due to neutron irradiation embrittlement and void swelling
- cracking due to SCC
- cracking due to cyclic loading
- loss of preload due to stress relaxation
- loss of material due to erosion
- cracking due to flow-induced vibration
- cracking due to SCC and IASCC
- cracking due to PWSCC
- wall thinning due to flow-accelerated corrosion
- changes in dimensions due to void swelling
- cracking due to SCC and PWSCC
- cracking due to SCC, PWSCC, and IASCC

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation. The staff determined whether the applicant adequately addressed the issues for which further evaluation is recommended. The staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.1.2.2. The staff's review of the applicant's further evaluation follows.

3.1.2.2.1 Cumulative Fatigue Damage

LRA Section 3.1.2.2.1 addresses the applicant's AMR basis for managing cumulative fatigue damage in ASME Code Class 1 components and ASME Code Class 2 components that were analyzed to ASME Code Section III, Class 1 CUF calculation criteria. In this LRA section, the applicant stated that the analysis of cumulative fatigue damage in the core spray, feedwater, HPCI, main steam, nuclear boiler instrumentation, RCIC, reactor internals, RPV, reactor recirculation, reactor water cleanup, and RHR systems RCPB piping, valves, and other components are TLAAs as defined in 10 CFR 54.3. The applicant stated that these TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1).

The applicant identified that the following AMRs in LRA Table 3.1.1 are applicable to this further evaluation item and that the analysis of metal fatigue for components addressed in these AMRs is a TLAA:

- Item 3.1.1-1: The applicant stated that the HCGS steel pressure vessel support skirt and attachment weld components were required to be analyzed in accordance with applicable ASME Code Section III CUF calculation criteria. In LRA Table 3.1.2-3, the applicant identified that the reactor vessel external attachments are analyzed for CUF analyses.

- Item 3.1.1-2: The applicant stated that the HCGS steel, stainless steel, steel with nickel-alloy or stainless steel cladding, nickel-alloy reactor vessel components, flanges, nozzles, penetrations, safe ends, thermal sleeves, vessel shells, heads, and welds were required to be analyzed in accordance with applicable ASME Code Section III CUF calculation criteria. In LRA Table 3.1.2-3, the applicant identified various nozzles, nozzle safe ends, nozzle thermal sleeves, penetrations, and the reactor vessel required to be analyzed for CUF analyses.

- Item 3.1.1-3: The applicant stated that the HCGS steel, stainless steel, steel with nickel-alloy or stainless steel cladding, nickel-alloy RCPB piping, piping components, and piping elements exposed to reactor coolant were required to be analyzed in accordance with applicable ASME Code Section III CUF calculation criteria. In LRA Tables 3.1.2-1, 3.1.2-4, 3.2.2-2, 3.2.2-4, 3.2.2-6, 3.2.2-7, 3.3.2-24, and 3.4.2-4, the applicant identified piping, fittings, branch connections, and valve bodies that were required to be analyzed for CUF analyses.

- Item 3.1.1-4: The applicant stated that the HCGS steel pump and valve closure bolting were required to be analyzed in accordance with applicable ASME Code Section III CUF calculation criteria. In LRA Tables 3.1.2-1, 3.1.2-3, 3.1.2-4, 3.2.2-2, 3.2.2-4, 3.2.2-6, 3.2.2-7, 3.3.2-24, 3.4.2-2, and 3.4.2-4, the applicant identified bolting that was required to be analyzed for CUF analyses.

- Item 3.1.1-5: The applicant stated that some of the HCGS RVI components designed to ASME Code Section III, Subsection NG requirements were required to be analyzed in accordance with applicable ASME Code Section III CUF calculation criteria. In LRA Table 3.1.2-2, the applicant identified that the following RVI components were required to be analyzed in accordance with an applicable CUF analysis: (1) RVI core shroud and core plate structures and (2) RVI top guide structure. The applicant stated that Section 4.3 describes the evaluation of these TLAAs.

The staff reviewed LRA Section 3.1.2.2.1 against the general criteria in SRP-LR Section 3.1.2.1 for performing AMR reviews, as subject to the additional further evaluation criteria in SRP-LR Section 3.1.2.2.1, which states that fatigue is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1) and in accordance with the staff’s recommended acceptance criteria and review procedures for reviewing these type of TLAAs in SRP-LR Section 4.3, “Metal Fatigue Analysis.” The staff also reviewed LRA Section 3.1.2.2.1 and the AMRs discussed in this section against the staff’s AMR items for evaluating BWR design cumulative fatigue damage in the GALL Report.

With regard to the applicant's metal fatigue AMR item 3.1.1-1, the staff noted that AMR item 1 in Table 1 of the GALL Report, Volume 1 and AMR items IV.A1-6 and IV.A2-20 in the GALL Report, Volume 2 identify that cumulative fatigue damage is an applicable aging effect for steel pressure vessel support skirt and attachment welds. The staff also noted that these GALL Report AMRs recommend that the TLAA on metal fatigue be used to manage the impact of cumulative fatigue damage in these components. The staff noted that, in conformance with this recommendation, the applicant included an applicable line item in LRA Table 3.1.2-3 for the reactor vessel external attachments that received ASME Code Section III CUF analysis calculations. The staff noted that the applicant credited the TLAA analysis in LRA Section 4.3.1 with the management of cumulative fatigue damage in these components. The staff found that the applicant's AMR assessment was in conformance with the recommendations in both the SRP-LR and in AMR item 1 of the GALL Report, Volume 1, Table 1 and AMR items IV.A1-6 and IV.A2-20 in the GALL Report, Volume 2. Based on this review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of support skirt and attachment welds components to be acceptable because it is in conformance with the recommendations in SRP-LR Section 3.1.2.2.1 and the GALL Report AMR items that are invoked by this SRP-LR section. The staff evaluates the TLAA analysis for the support skirt and attachment welds component in SER Section 4.3.1.

With regard to the applicant's metal fatigue AMR item 3.1.1-2, the staff noted that AMR item 2 in Table 1 of the GALL Report, Volume 1 and AMR item IV.A1-7 in the GALL Report, Volume 2 identify that cumulative fatigue damage is an applicable aging effect for steel, stainless steel, steel with nickel-alloy or stainless steel cladding, nickel-alloy reactor vessel components, flanges, nozzles, penetrations, safe ends, thermal sleeves, vessel shells, heads, and welds. The staff also noted that these GALL Report AMRs recommend that the TLAA on metal fatigue be used to manage the impact of cumulative fatigue damage in these components. The staff noted that, in conformance with this recommendation, the applicant included applicable line items in LRA Table 3.1.2-3 for various nozzles, nozzle safe ends, nozzle thermal sleeves, penetrations, and the reactor vessel that received ASME Code Section III CUF analysis calculations. The staff noted that the applicant credited the TLAA analysis in LRA Section 4.3.1 with the management of cumulative fatigue damage in these components. The staff found that the applicant's AMR assessment was in conformance with the recommendations in both the SRP-LR and in AMR item 2 of GALL Report, Volume 1, Table 1 and AMR item IV.A1-7 in the GALL Report, Volume 2. Based on this review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of reactor vessel components, flanges, nozzles, penetrations, safe ends, thermal sleeves, vessel shells, heads, and welds to be acceptable because it is in conformance with the recommendations in SRP-LR Section 3.1.2.2.1 and the GALL Report AMR items that are invoked by this SRP-LR section. The staff evaluates the TLAA analysis for the reactor vessel components, flanges, nozzles, penetrations, safe ends, thermal sleeves, vessel shells, heads, and welds components in SER Section 4.3.1.

With regard to the applicant's metal fatigue AMR item 3.1.1-3, the staff noted that AMR item 3 in Table 1 of the GALL Report, Volume 1 and AMR item IV.C1-15 in the GALL Report, Volume 2 identify that cumulative fatigue damage is an applicable aging effect for steel, stainless steel, steel with nickel-alloy or stainless steel cladding, nickel-alloy RCPB piping, piping components, and piping elements exposed to reactor coolant. The staff also noted that these GALL Report AMRs recommend that the TLAA on metal fatigue be used to manage the impact of cumulative fatigue damage in these components. The staff noted that, in conformance with this recommendation, the applicant included applicable line items in LRA Tables 3.1.2-1, 3.1.2-4, 3.2.2-2, 3.2.2-4, 3.2.2-6, 3.2.2-7, 3.3.2-24, and 3.4.2-4 for piping, fittings, branch connections and valve bodies that received ASME Code Section III CUF analysis calculations. The staff noted that the applicant credited the TLAA analysis in LRA Sections 4.3.3 and 4.3.4 with the management of cumulative fatigue damage in these components. The staff found that the applicant's AMR assessment was in conformance with the recommendations in both the SRP-LR and in AMR item 3 of the GALL Report, Volume 1, Table 1 and AMR item IV.C1-15 in the GALL Report, Volume 2. Based on this review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of piping, piping components, and piping elements components to be acceptable because it is in conformance with the recommendations in SRP-LR Section 3.1.2.2.1 and the GALL Report AMR items that are invoked by this SRP-LR section. The staff evaluates the TLAA analysis for the piping, piping components, and piping elements components in SER Sections 4.3.3 and 4.3.4.

With regard to the applicant's metal fatigue AMR item 3.1.1-4, the staff noted that AMR item 4 in Table 1 of the GALL Report, Volume 1 and AMR item IV.C1-11 in the GALL Report, Volume 2 identify that cumulative fatigue damage is an applicable aging effect for steel pump and valve closure bolting. The staff also noted that these GALL Report AMRs recommend that the TLAA on metal fatigue be used to manage the impact of cumulative fatigue damage in these components. The staff noted that, in conformance with this recommendation, the applicant included applicable line items in LRA Tables 3.1.2-1, 3.1.2-3, 3.1.2-4, 3.2.2-2, 3.2.2-4, 3.2.2-6, 3.2.2-7, 3.3.2-24, 3.4.2-2, and 3.4.2-4 for bolting that received ASME Code Section III CUF analysis calculations. The staff noted that the applicant credited the TLAA analysis in LRA Section 4.3.1 with the management of cumulative fatigue damage in these components. The staff found that the applicant's AMR assessment was in conformance with the recommendations in both the SRP-LR and in AMR item 4 of the GALL Report, Volume 1, Table 1 and AMR item IV.C1-11 in the GALL Report, Volume 2. Based on this review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of pump and valve closure bolting components to be acceptable because it is in conformance with the recommendations in SRP-LR Section 3.1.2.2.1 and the GALL Report AMR items that are invoked by this SRP-LR section. The staff evaluates the TLAA analysis for the pump and valve closure bolting components in SER Section 4.3.1.

With regard to the applicant's metal fatigue AMR item 3.1.1-5, the staff noted that AMR item 5 in Table 1 of the GALL Report, Volume 1 and AMR item IV.B1-14 in the GALL Report, Volume 2 identify that cumulative fatigue damage is an applicable aging effect for RVI components. The staff also noted that these GALL Report AMRs recommend that the TLAA on metal fatigue be used to manage the impact of cumulative fatigue damage in these components. The staff noted that, in conformance with this recommendation, the applicant included applicable line items in LRA Tables 3.1.2-2 for RVI components that received ASME Code Section III CUF analysis calculations. The staff noted that the applicant credited the TLAA analysis in LRA Section 4.3.2 with the management of cumulative fatigue damage in these components. The staff found that the applicant's AMR assessment was in conformance with the recommendations in both the SRP-LR and in AMR item 5 of the GALL Report, Volume 1, Table 1 and AMR item IV.B1-14 in the GALL Report, Volume 2. Based on this review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of pump and valve closure bolting components to be acceptable because it is in conformance with the recommendations in SRP-LR Section 3.1.2.2.1 and the GALL Report AMR items that are invoked by this SRP-LR section. The staff evaluates the TLAA analysis for the RVI components in SER Section 4.3.2.

With regard to the applicant's metal fatigue AMR items 3.1.1-6, 3.1.1-7, 3.1.1-8, 3.1.1-9, and 3.1.1-10, the applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.1 states that fatigue is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). SRP-LR Table 3.1-1 identifies items 6, 7, 8, 9, and 10 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.1 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWRs.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.5 do not apply to HCGS because the guidance is applicable to PWRs.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.1 criteria. For those items that apply to LRA Section 3.1.2.2.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.1.2.2.2 against the criteria in SRP-LR Section 3.1.2.2.2.

(1) LRA Section 3.1.2.2.2 is associated with LRA Table 3.1.1, item 3.1.1-11 and addresses carbon and low alloy steel for the reactor vessel nozzles, nozzle safe ends and welds, RCPB components, RVI attachments, and reactor vessel top head and flange exposed to reactor coolant which are being managed for loss of material due to general, pitting, and crevice corrosion by the Water Chemistry Control and the One-Time Inspection programs. The applicant addressed the further evaluation requirement by stating that it will implement the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program. The applicant further stated that LRA Table 3.1.1, item 3.1.1-12 is only applicable to PWR designs and is, therefore, not applicable to HCGS.

    The staff reviewed LRA Section 3.1.2.2.2, item 1 against the criteria in SRP-LR Section 3.1.2.2.2, item 1, which states that loss of material due to general, pitting, and crevice corrosion could occur for steel top head enclosure (without cladding) top head nozzles (vent, top head spray, or RCIC and spare) exposed to reactor coolant. The SRP-LR also states that control of water chemistry does not preclude loss of material due to general, pitting, and crevice corrosion at locations of stagnant flow conditions. Therefore, the effectiveness of the chemistry control program should be verified to ensure that corrosion does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring, or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

    The applicant stated that item 3.1.1.-12 is not applicable because it is applicable to PWRs only. The staff finds the applicant's determination acceptable for item 3.1.1-12.

    The staff's evaluation of the applicant's Water Chemistry Program and One-Time Inspection Program is documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. The staff determined that the Water Chemistry Program includes activities to mitigate aging effects on component surfaces by controlling water chemistry for impurities such as dissolved oxygen, chlorides, fluorides, and sulfates that can potentially accelerate corrosion and cracking. The staff further determined that this program relies on monitoring and control of water chemistry in order to keep the peak levels of various impurities below the specified limits. The staff noted that by keeping the impurities within the guidance of BWRVIP-130, the applicant can mitigate the damage from the active aging mechanism (loss of material due to general, crevice, and pitting corrosion). The staff determined that the applicant's One-Time Inspection Program will also verify the effectiveness of its Water Chemistry Program.

In its review of components associated with item 3.1.1-11, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program and the One-Time Inspection Program acceptable because the Water Chemistry Program monitors and controls the chemical environment (impurities) of the RCPB components that are exposed to reactor coolant and will be supplemented by the One-Time Inspection Program to confirm the effectiveness of the Water Chemistry Program, consistent with the recommendations in the GALL Report.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.2, item 1 criteria. For those line items that apply to LRA Section 3.1.2.2.2, item 1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.1.2.2.2.2 is associated with Table 3.1.1, item 3.1.1-13 and addresses carbon steel piping and fittings exposed to treated water and steam in the core spray, feedwater, HPCI, main steam, nuclear boiler instrumentation, RCIC, reactor recirculation, reactor water cleanup, and RHR systems, which are being managed for loss of material due to general (steel only), pitting, and crevice corrosion by the Water Chemistry and One-Time Inspection Programs. The applicant stated that it does not have isolation condensers. The applicant addressed the further evaluation requirements by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Water Chemistry Program.

The staff reviewed LRA Section 3.1.2.2.2, item 2 against the criteria in SRP-LR Section 3.1.2.2.2, item 2, which states that: (1) loss of material due to general, pitting, and crevice corrosion could occur for stainless steel BWR isolation condenser components exposed to reactor coolant; (2) the existing AMP relies on monitoring and control of water chemistry to manage the effects of loss of material due to general, pitting, and crevice corrosion; and (3) control of water chemistry does not preclude loss of material due to general, pitting, and crevice corrosion at locations of stagnant flow conditions. The effectiveness of the Water Chemistry Program, therefore, should be verified using a one-time inspection to ensure that corrosion does not occur. The GALL Report recommends a one-time inspection of select components at susceptible locations as an acceptable method to verify the effectiveness of the Water Chemistry Program and ensure that an aging effect is not occurring, or is progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. The staff finds the applicant's combination of programs acceptable to manage loss of material because these programs: (1) provide for periodic sampling of treated water to maintain contaminants at acceptable limits to preclude loss of material due to general, pitting, and crevice corrosion; and (2) will perform one-time inspections to verify the effectiveness of the Water Chemistry Program.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.2, item 2 criteria. For those line items that apply to LRA Section 3.1.2.2.2, item 2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(3) LRA Section 3.1.2.2.2 is referenced by LRA Table 3.1.1, items 3.1.1-14 and 3.1.1-15 and addresses stainless steel, nickel-alloy, and steel with nickel-alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, pressure housings, safe ends, and vessel shell, heads, and welds exposed to reactor coolant which are being managed for loss of material due to pitting and crevice corrosion by the Water Chemistry and the One-Time Inspection Programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will implement a One-Time Inspection Program to manage the loss of material due to general, pitting, and crevice corrosion of stainless steel, CASS, nickel-alloy, and steel with stainless steel cladding for reactor vessel flange, nozzles, penetrations, safe ends, thermal sleeves, vessel shells, heads, welds, and RCPB components including piping, piping elements, and piping components exposed to treated water and steam at susceptible locations.

The staff reviewed LRA Section 3.1.2.2.2, item 3 against the criteria in SRP-LR Section 3.1.2.2.2, item 3, which states that: (1) loss of material due to pitting and crevice corrosion could occur for stainless steel, nickel-alloy, and steel with stainless steel or nickel-alloy cladding flanges, nozzles, penetrations, pressure housings, safe ends, and vessel shells, heads, and welds exposed to reactor coolant; (2) the existing AMP relies on monitoring and control of water chemistry to mitigate corrosion; and (3) control of water chemistry does not preclude corrosion at locations of stagnant flow conditions. The effectiveness of the water chemistry program, therefore, should be verified using a one-time inspection to ensure that corrosion does not occur. The GALL Report recommends a one-time inspection of select components at susceptible locations as an acceptable method to verify the effectiveness of the Water Chemistry Program and ensure that an aging effect is not occurring, or is progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's Water Chemistry Program. The staff's evaluation of this program, which is documented in SER Section 3.0.3.2.1, found that the applicant's Water Chemistry Program follows the guidelines in BWRVIP-130 and will provide mitigation for the aging effect of loss of material due to pitting and crevice corrosion. The staff reviewed the applicant's One-Time Inspection Program, which is documented in SER Section 3.0.3.1.11, and found that the applicant's AMP is consistent with the GALL Report's recommendations for GALL AMP XI.M32, "One-Time Inspection." The applicant's One-Time Inspection Program includes provisions for inspecting select components in areas of low or stagnant flow and is capable of detecting loss of material due to pitting and crevice corrosion, if it should occur in the selected components. The applicant's One-Time Inspection Program is acceptable for verification because: (1) the aging effects progress very slowly so that the performance of the RCPB components is not compromised, and (2) it is listed as an acceptable method in the SRP-LR.

In its review of components associated with AMR item 3.1.1-15, the staff noted that CASS is not listed as one of the materials. Additionally, for CASS flow elements, SRP-LR Table 3.1-1, item 57 recommends aging management for loss of fracture toughness due to thermal aging embrittlement. However, LRA Table 3.4.2-4 includes two 3.1.1-15 line items under Table 1 items (flow elements, Class 1) with CASS as the material, and credits the Water Chemistry and the One-Time Inspection Programs. In its letter dated June 14, 2010, the staff issued RAI 3.1.1-15-1 requesting that the applicant explain why: (1) AMR item 3.1.1-57 is not applicable when the GALL Report only exempts pump and valve bodies and (2) the flow elements associated with AMR item 3.1.1-15 do not credit GALL AMP XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS),” to manage loss of fracture toughness/thermal aging embrittlement.

In a letter dated July 12, 2010, the applicant responded to RAI 3.1.1-15-1 by providing the following response:

(a) Hope Creek LRA Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System, on Pages 3.1-36 and 3.1-37, provides the following discussion for why line item 3.1.1-57 is not applicable to Hope Creek.

The Class 1 CASS flow restrictor nozzles in the Main Steam System are not susceptible to thermal embrittlement because the nozzles were cast by a centrifugal casting method using low molybdenum stainless material (SA351 CF8). In accordance with the guidance provided in the NUREG-1801, Volume 2, Section XI.M12, the centrifugally cast, low molybdenum CASS portion of the flow restrictors is not susceptible to thermal aging embrittlement.

(b) Based on the above, loss of fracture toughness/thermal aging embrittlement is not an applicable aging effect/mechanism for the CASS nozzle sections of the Main Steam flow elements associated with AMR line item 3.1.1-15. In addition, GALL AMP XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) states:

> *Scope of Program*: The program includes screening criteria to determine which CASS components are potentially susceptible to thermal aging embrittlement and require augmented inspection. The screening criteria are applicable to all primary pressure boundary and reactor vessel internal components constructed from SA-351 Grades CF3,CF3A, CF8, CF8A, CF3M, CF3MA, CF8M, with service conditions above 250 C (482°F).

The CASS nozzle sections of the Main Steam flow elements are not primary pressure boundary or reactor vessel internal components. Therefore, GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program is not used for Hope Creek.”

The staff reviewed the applicant’s response to RAI 3.1.1-15-1 and confirmed that the CASS flow elements associated with AMR item 3.1.1-15 should not be susceptible to thermal aging embrittlement. Therefore, the staff’s concern described in RAI 3.1.1-15-1 is resolved.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.2.3 criteria. For those line items that apply to LRA Section 3.1.2.2.2.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(4) LRA Section 3.1.2.2.2.4 refers to Table 3.1.1, item 3.1.1-16 and addresses loss of material due to general, pitting, and crevice corrosion. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.2.4 states that loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam. SRP-LR Table 3.1-1 identifies item 6 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.2.4 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR nickel-alloy tubes and sleeves in a reactor coolant and secondary feedwater and steam environment.

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.2 criteria. For those line items that apply to LRA Section 3.1.2.2.2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

The staff reviewed LRA Section 3.1.2.2.3 against the following criteria in SRP-LR Section 3.1.2.2.3:

(1) LRA Section 3.1.2.2.3 refers to Table 3.1.1, item 3.1.1-17 and states that neutron irradiation embrittlement is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4.2 documents the staff's review of the applicant's evaluation of this TLAA.

(2) LRA Section 3.1.2.2.3 refers to LRA Table 3.1.2-3, item 3.1.1-18 and addresses RPV carbon or low alloy steel with stainless steel cladding exposed to reactor coolant and neutron flux (internal) which are being managed for loss of fracture toughness due to neutron irradiation embrittlement by the Reactor Vessel Surveillance Program. The applicant addressed the further evaluation requirement by stating that the Reactor Vessel Surveillance Program relies on the BWRVIP ISP and satisfies the requirements of 10 CFR Part 50, Appendix H. The Reactor Vessel Surveillance Program includes periodic testing of metallurgical surveillance samples to monitor the progress of neutron embrittlement of the RPV as a function of neutron fluence, in accordance with RG 1.99, "Radiation Embrittlement of Reactor Vessel Materials," Revision 2. BWRVIP-116 identifies and schedules additional capsules to be withdrawn and tested during the period of extended operation. HCGS will continue using the ISP during the period of extended operation by implementing the requirements of BWRVIP-116. The BWRVIP-116 (NRC Safety Evaluation dated February 24, 2006) report incorporates the

technical criteria specified in BWRVIP-86-A (approved by the staff in an SER dated February 1, 2002) and extends the ISP to cover the BWR fleet through the period of extended operation. The Reactor Vessel Surveillance Program will adequately identify, evaluate, and manage the effects of loss of fracture toughness due to neutron irradiation embrittlement of the steel with stainless steel cladding of the reactor vessel to ensure there is no loss of intended function during the period of extended operation.

The staff reviewed LRA Section 3.1.2.2.3, item 2 against the criteria in SRP-LR Section 3.1.2.2.3, item 2, which states that loss of fracture toughness due to neutron irradiation embrittlement could occur in BWR reactor vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux. The SRP-LR also states that the applicant must implement a reactor surveillance program that follows the requirements of 10 CFR Part 50, Appendix H by incorporating plant-specific factors such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels. In addition, the plant-specific program must provide for untested capsules to be maintained in a manner such that they could be re-inserted into the vessel in the future if the need arises. The staff also notes that the applicant has committed (Commitment No. 21) to establishing restrictions that will ensure that the plant is operated within the conditions to which the surveillance capsules were exposed.

The staff's evaluation of the applicant's Reactor Vessel Surveillance program is documented in SER Section 3.0.3.2.11. The staff noted the applicant's program consists of periodic testing of metallurgical surveillance samples to monitor the progress of neutron embrittlement of the RPV as a function of neutron fluence that is capable of identifying, evaluating, and managing the effects of loss of fracture toughness due to neutron irradiation embrittlement of the steel with stainless steel cladding of the reactor vessel.

In its review of components associated with item 3.1.1-18, the staff finds the applicant's proposal to manage aging using the Reactor Vessel Surveillance Program acceptable because the applicant has committed to implementation of the BWRVIP-116 ISP. The staff noted that this industry program does provide for testing of the most sensitive beltline material from HCGS at a fluence that is representative of 56 EFPY at HCGS. The staff also noted that all of the HCGS capsules are already tested or slated for testing as part of the ISP; there are no extra capsules that could be removed without testing.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.3, item 2 criteria. For those line items that apply to LRA Section 3.1.2.2.3, item 2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.3 criteria. For those line items that apply to LRA Section 3.1.2.2.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.4 Cracking Due to SCC and IGSCC

The staff reviewed LRA Section 3.1.2.2.4 against the criteria in SRP-LR Section 3.1.2.2.4.

(1) LRA Section 3.1.2.2.4.1 refers to Table 3.1.1, item 3.1.1-19 and addresses the stainless steel vessel flange leak detection line exposed to treated water which is being managed for cracking due to SCC or IGSCC by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and the Water Chemistry Program. The applicant addressed the further evaluation requirements by stating that the Water Chemistry Program monitors and controls water chemistry in accordance with EPRI BWR Water Chemistry Guidelines and that control of water chemistry within the guidelines prevents or mitigates cracking due to SCC or IGSCC. The applicant further stated that its current ISI program, through a currently approved relief request, uses a VT-2 visual examination on the vessel flange leak detection line, prior to reactor cavity drain down during each refueling outage.

The staff reviewed LRA Section 3.1.2.2.4.1 against the criteria in SRP-LR Section 3.1.2.2.4.1, which states that cracking due to SCC or IGSCC could occur in the stainless steel and nickel-alloy BWR top head enclosure vessel flange leak detection lines. The GALL Report recommends that a plant-specific AMP be evaluated because existing programs may not be capable of mitigating or detecting crack initiation and growth due to SCC and IGSCC in the vessel flange leak detection line.

In its review of components subordinate to LRA item 3.1.1-19, the staff noted that the applicant’s current relief request related to VT-2 visual examination of the flange leak detection line is approved only for the current 10-year ISI interval and does not extend into the period of extended operation. The staff further noted that during the VT-2 examination, the line is pressurized only by the static head of water above the flange. By letter dated June 9, 2010, the staff issued RAI 3.1.2.2.4.1 requesting that the applicant explain: (1) how a VT-2 examination will detect cracking due to SCC or IGSCC in the vessel flange leak detection line prior to failure of the line’s intended function, and (2) how aging of the vessel flange leak detection line will be managed without referring to implementation of a relief request which has neither been requested nor approved for the period of extended operation.

By letter dated July 6, 2010, the applicant provided a response to RAI 3.1.2.2.4.1. In its review of the applicant’s response, the staff noted that the applicant proposed to manage the aging effect of cracking due to SCC with a combination of the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff also noted that there was no proposed augmentation of the ASME Code Section XI requirement applicable for the vessel flange leak detection line and that the applicant did not provide sufficient information for the staff to conclude that the applicable VT-2 leakage testing of the component is capable of detecting crack initiation prior to failure of the component’s intended function. On August 5, 2010, the staff and the applicant held a telephone conference to discuss issues with the applicant’s response to RAI 3.1.2.2.4.1. As a result of this conference, the applicant provided a revised response in a letter dated August 26, 2010.

In its revised response to RAI 3.1.2.2.4.1, the applicant stated that it will manage cracking due to SCC or IGSCC in the stainless steel vessel flange leak detection line using the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and the Water Chemistry Program, plus a one-time volumetric examination of the line for cracking in accordance with its One-Time Inspection Program. The applicant revised appropriate LRA tables and discussions to reflect this change. This resulted in changes to LRA Table 3.1.1, item 3.1.1-19; Table 3.4.2-4; and Subsection 3.1.2.2.4.

Based on its review of the applicant's response to RAI 3.1.2.2.4.1, as amended by letter dated August 26, 2010, the staff finds that: (1) the monitoring and control for water chemistry mitigates the likelihood of cracking, (2) the volumetric examination performed prior to the period of extended operation provides assurance that there is no cracking in the vessel flange leak detection line, and (3) the VT-2 examination provides ongoing periodic confirmation that physical integrity of the line is maintained during the period of extended operation. Therefore, the staff's concern described in RAI 3.1.2.2.4.1 is resolved.

The staff's evaluation of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program; Water Chemistry Program; and One-Time Inspection Program are documented in SER Sections 3.0.3.1.1, 3.0.3.2.1, and 3.0.3.1.11, respectively. In its review of components associated with item 3.1.1-19, the staff finds the applicant's proposal to manage aging using the combination of these three programs acceptable because: (1) the Water Chemistry Program provides monitoring and control for water chemistry to mitigate the likelihood of cracking due to SCC or IGSCC; (2) the volumetric examination, performed in accordance with the One-Time Inspection Program, provides assurance that there is no cracking in the vessel flange leak detection line prior to entering the period of extended operation; and (3) the VT-2 examination in accordance with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program provides ongoing periodic confirmation that physical integrity of the line is maintained during the period of extended operation.

On this basis, the staff finds that the revised response to RAI 3.1.2.2.4.1, as documented in the applicant's letter dated August 26, 2010, resolves all issues addressed in the RAI.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.4, item 1 criteria. For those line items that apply to LRA Section 3.1.2.2.4, item 1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.1.2.2.4.2 refers to Table 3.1.1, item 3.1.1-20 and addresses the stainless steel isolation condenser components exposed to reactor coolant. The applicant stated this aging effect is not applicable because HCGS does not have isolation condensers.

SRP-LR Section 3.1.2.2.4 states that cracking due to SCC and IGSCC may occur in stainless steel BWR isolation condenser components exposed to reactor coolant.

The staff reviewed the applicant's UFSAR and finds that SRP-LR Section 3.1.2.2.4, item 2 is not applicable to HCGS because HCGS does not have an isolation condenser and the staff guidance in this SRP-LR section is only applicable to BWRs with isolation condenser components.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.4, item 2 do not apply to HCGS because the guidance is applicable to BWRs with isolation condenser components.

3.1.2.2.5 Crack Growth Due to Cyclic Loading

LRA Section 3.1.2.2.5 refers to Table 3.1.1, item 3.1.1-21 and addresses crack growth due to cyclic loading. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.5 states that crack growth due to cyclic loading could occur in reactor vessel shell forgings clad with stainless steel using a high-heat-input welding process. SRP-LR Table 3.1-1 identifies item 21 as applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.5 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR-designed reactor vessel shells fabricated of SA508-CI forgings clad with stainless steel using a high-heat-input welding process.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.5 do not apply to HCGS because the guidance is applicable to PWRs.

3.1.2.2.6 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement and Void Swelling

LRA Section 3.1.2.2.6 refers to Table 3.1.1, item 3.1.1-22 and addresses loss of fracture toughness due to neutron irradiation embrittlement and void swelling. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.6 states that loss of fracture toughness due to neutron irradiation embrittlement and void swelling could occur in stainless steel and nickel-alloy RVI components exposed to reactor coolant and neutron flux. SRP-LR Table 3.1-1 identifies item 22 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.5 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR stainless steel and nickel-alloy RVI components exposed to reactor coolant and neutron flux.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.6 do not apply to HCGS because the guidance is applicable to PWRs.

3.1.2.2.7 Cracking Due to Stress-Corrosion Cracking

(1) LRA Section 3.1.2.2.7.1 refers to Table 3.1.1, item 3.1.1-23 and addresses cracking due to SCC. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.7.1 states that cracking due to SCC could occur in the PWR stainless steel reactor vessel flange leak detection lines and bottom-mounted instrument guide tubes exposed to reactor coolant. SRP-LR Table 3.1-1 identifies item 23 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.7.1 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR stainless steel reactor vessel closure head flange leak detection line and bottom-mounted instrument guide tubes.

(2) LRA Section 3.1.2.2.7.2 refers to Table 3.1.1, item 3.1.1-24 and addresses cracking due to SCC. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.7.2 states that cracking due to SCC could occur in Class 1 PWR CASS RCS piping, piping components, and piping elements exposed to reactor coolant. SRP-LR Table 3.1-1 identifies item 24 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.7.2 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR Class 1 CASS piping, piping components, and piping elements exposed to reactor coolant.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.7,"Items 1 and 2 do not apply to HCGS because the guidance is applicable to PWRs.

3.1.2.2.8 Cracking Due to Cyclic Loading

(1) LRA Section 3.1.2.2.8.1 refers to Table 3.1.1, item 3.1.1-25 and addresses cracking due to cyclic loading. The applicant stated that this aging effect is not applicable because stainless steel jet pump sensing lines internal to the reactor vessel are not required to support intended functions and are not included within the scope of license renewal. A safety assessment for these components has been performed and reported in BWRVIP-06. The evaluation concluded that these components do not perform a safety-related function. This report also concluded that failure of these components will not result in consequential failure of any safety-related equipment. The lines outside of the vessel are not subjected to flow-induced vibration, but are part of the RCPB and are subject to an AMR. Cracking due to SCC, and thermal and mechanical loading of the stainless steel lines external to the reactor vessel are addressed by Table 3.1.1, item 3.1.1-48.

SRP-LR Section 3.1.2.2.8.1 states that cracking due to cyclic loading could occur in the stainless steel BWR jet pump sensing lines.

The staff reviewed the BWRVIP-06 and the applicant's UFSAR and finds that SRP-LR Section 3.1.2.2.8, item 1 is not applicable to HCGS because jet pump sensing lines do not perform a safety-related function and failure of these components will not result in consequential failure of any safety-related equipment. Also, lines outside of the vessel are subject to an AMR and the aging effects of cracking due to SCC, and thermal and mechanical loading of the stainless steel lines external to the reactor vessel are being addressed by Table 3.1.1, item 3.1.1-48.

(2) LRA Section 3.1.2.2.8.2 refers to Table 3.1.1, item 3.1.1-26 and addresses cracking due to cyclic loading. The applicant stated this aging effect is not applicable because HCGS does not have isolation condensers.

SRP-LR Section 3.1.2.2.8.2 states that cracking due to cycling loading could occur in steel and stainless steel BWR isolation condenser components exposed to reactor coolant.

The staff reviewed the applicant's UFSAR and finds that SRP-LR Section 3.1.2.2.8.2, item 2 is not applicable to HCGS because HCGS does not have an isolation condenser, and the staff guidance in this SRP-LR section is only applicable to BWRs with isolation condenser components.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.8, items 1 and 2 do not apply to HCGS because stainless steel jet pump sensing lines internal to the reactor vessel are not included within the scope of license renewal but are being addressed by Table 3.1.1, item 3.1.1-48 and HCGS does not have isolation condensers.

3.1.2.2.9 Loss of Preload Due to Stress Relaxation

LRA Section 3.1.2.2.9 refers to Table 3.1.1, item 3.1.1-27 and addresses loss of preload due to stress relaxation. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.9 states that loss of preload due to stress relaxation could occur in stainless steel and nickel-alloy PWR RVI screws, bolts, tie rods, and hold down springs exposed to reactor coolant. SRP-LR Table 3.1-1 identifies item 27 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.9 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR stainless steel and nickel-alloy RVI screws, bolts, tie rods, and hold down springs.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.9 do not apply to HCGS because the guidance is applicable to PWRs.

3.1.2.2.10 Loss of Material Due to Erosion

LRA Section 3.1.2.2.10 refers to Table 3.1.1, item 3.1.1-28 and addresses loss of material due to erosion. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.10 states that loss of material due to erosion could occur in steel steam generator feedwater impingement plates and supports exposed to secondary feedwater. SRP-LR Table 3.1-1 identifies item 28 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.10 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR steel steam generator feedwater impingment plates and supports exposed to secondary feedwater.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.10 do not apply to HCGS because the guidance is applicable to PWRs.

3.1.2.2.11 Cracking Due to Flow-Induced Vibration

LRA Section 3.1.2.2.11 refers to LRA Table 3.1.1, item 3.1.1-29 and addresses reactor internals stainless steel and CASS steam dryer components exposed to reactor coolant which are being managed for cracking due to flow-induced vibration by the BWR Vessel Internals Program. The applicant addressed the further evaluation requirements by stating that the BWR Vessel

Internals Program inspects, evaluates, and repairs flaws, in accordance with the guidelines provided in BWRVIP-139, "BWR Vessel and Internals Project Steam Dryer Inspection and Flaw Evaluation." The applicant further stated that following the guidelines in BWRVIP-139 will adequately identify, evaluate, and manage the effects of cracking due to flow-induced vibration of the CASS and stainless steel steam dryer components.

The staff reviewed LRA Section 3.1.2.2.11 against the criteria in SRP-LR Section 3.1.2.2.11, which states that cracking due to flow-induced vibration could occur for BWR stainless steel steam dryers exposed to reactor coolant. The SRP-LR also recommends further evaluation of a plant-specific AMP to ensure that this aging effect is adequately managed. The staff reviewed the applicant's experience with cracking in steam dryers and notes that fatigue cracking in the steam dryer components has been found at other plants after EPU, but not at HCGS.

The staff's evaluation of the applicant's BWR Vessel Internals Program is documented in SER Section 3.0.3.1.7. The staff noted that the BWR Vessel Internals Program includes inspection of the steam dryer that is in accordance with BWRVIP-139 guidance. The staff issued its safety evaluation (SE) on BWRVIP-139 in a letter to the EPRI, dated July 30, 2008. In its SE, the staff stated that the guidelines below should be followed for re-inspection:

- Each BWR applicant will determine the appropriate re-inspection approach according to GE SIL-644 or BWRVIP-139 in consideration of the steam dryer performance at its plant.

- License conditions associated with steam dryer monitoring programs in power uprate license amendments take precedence over the steam dryer re-inspection provisions in GE SIL-644 or BWRVIP-139.

- The applicant will justify any adjustments to its steam dryer re-inspection program where commitments exist to implement the re-inspection provisions in GE SIL-644 to support a power uprate license amendment or other activities.

- The applicant is expected to inform the staff of significant changes to its steam dryer re-inspection program where the staff relied on the program in a regulatory decision.

In its review of components associated with item 3.1.1-29, the staff finds the applicant's proposal to manage aging using the BWR Vessel Internals Program acceptable because the applicant is implementing the guidelines of BWRVIP-139 as accepted by the staff in the SE, and the applicant's BWR Vessel Internals Program incorporates the guidelines of BWRVIP-139.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.11 criteria. For those line items that apply to LRA Section 3.1.2.2.11, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.12 Cracking Due to Stress-Corrosion Cracking and Irradiation-Assisted Stress-Corrosion Cracking

LRA Section 3.1.2.2.12 refers to Table 3.1.1, item 3.1.1-30 and addresses cracking due to SCC and IASCC. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.12 states that cracking due to SCC and IASCC could occur in PWR stainless steel reactor internals exposed to reactor coolant. SRP-LR Table 3.1-1 identifies item 30 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.12 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR stainless steel RVI components.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.12 do not apply to HCGS because the guidance is applicable to a PWR.

3.1.2.2.13 Cracking Due to Primary Water Stress-Corrosion Cracking

LRA Section 3.1.2.2.13 refers to Table 3.1.1, item 3.1.1-31 and addresses cracking due to PWSCC. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.13 states that cracking due to PWSCC could occur in PWR components made of nickel alloy and steel with nickel-alloy cladding, including RCPB components and penetrations inside the RCS, such as pressurizer heater sheaths and sleeves, nozzles, and other internal components. SRP-LR Table 3.1-1 identifies item 31 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.13 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR nickel alloy and steel with nickel-alloy cladding piping, piping components, piping elements, penetration, nozzles, safe ends, and weld; pressurizer heater sheaths, sleeves, diaphragm plate, manways and flanges; and core support pads and core guide lugs.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.13 do not apply to HCGS because the guidance is applicable to PWRs.

3.1.2.2.14 Wall Thinning Due to Flow-Accelerated Corrosion

LRA Section 3.1.2.2.14 refers to Table 3.1.1, item 3.1.1-32 and addresses wall thinning due to flow-accelerated corrosion. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.14 states that wall thinning due to flow-accelerated corrosion could occur in steel feedwater inlet rings and supports. SRP-LR Table 3.1-1 identifies item 32 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.14 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR steel steam generator feedwater inlet rings and supports.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.14 do not apply to HCGS because the guidance is applicable to PWRs.

3.1.2.2.15 Changes in Dimensions Due to Void Swelling

LRA Section 3.1.2.2.15 refers to Table 3.1.1, item 3.1.1-33 and addresses changes in dimensions due to void swelling. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.15 states that changes in dimensions due to void swelling could occur in stainless steel and nickel-alloy PWR reactor internal components exposed to reactor coolant. SRP-LR Table 3.1-1 identifies item 33 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.15 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR stainless steel and nickel-alloy RVI components.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.15 do not apply to HCGS because the guidance is applicable to PWRs.

3.1.2.2.16 Cracking Due to Stress-Corrosion Cracking and Primary Water Stress-Corrosion Cracking

(1) LRA Section 3.1.2.2.16.1 refers to Table 3.1.1, items 3.1.1-34 and 3.1.1-35 and addresses cracking due to SCC and PWSCC. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.16.1 states that cracking due to SCC could occur on the primary coolant side of PWR steel steam generator upper and lower heads, tubesheets, and tube-to-tube sheet welds made or clad with stainless steel. Cracking due to PWSCC could occur on the primary coolant side of PWR steel steam generator upper and lower heads, tubesheets, and tube-to-tube sheet welds made or clad with nickel alloy. SRP-LR Table 3.1-1 identifies items 34 and 35 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.16.1 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWRs.

(2) LRA Section 3.1.2.2.16.2 refers to Table 3.1.1, item 3.1.1-36 and addresses cracking due to SCC and PWSCC. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.16.2 states that cracking due to SCC could occur on stainless steel pressurizer spray heads. Cracking due to PWSCC could occur on nickel-alloy pressurizer spray heads. SRP-LR Table 3.1-1 identifies item 36 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.16.2 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR nickel-alloy, stainless steel pressurizer spray heads.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.16, items 1 and 2 do not apply to HCGS because the guidance is applicable to PWRs.

3.1.2.2.17 Cracking Due to Stress-Corrosion Cracking, Primary Water Stress-Corrosion Cracking, and Irradiation-Assisted Stress-Corrosion Cracking

LRA Section 3.1.2.2.17 refers to Table 3.1.1, item 3.1.1-37 and addresses cracking due to SCC, PWSCC, and IASCC. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.1.2.2.17 states that cracking due to SCC, PWSCC, and IASCC could occur in PWR stainless steel and nickel-alloy RVI components. SRP-LR Table 3.1-1 identifies item 37 applicable to PWRs.

The staff verified that SRP-LR Section 3.1.2.2.17 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR stainless steel and nickel-alloy RVI components.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.17 do not apply to HCGS because the guidance is applicable to PWRs.

3.1.2.2.18 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA program.

3.1.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.1.2-1 through 3.1.2-4, the staff reviewed additional details of AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.1.2-1 through 3.1.2-4, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information concerning how the aging effects will be managed. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the aging effects will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.1.2.3.1 Reactor Vessel, Internals, and Reactor Coolant System – Nuclear Boiler Instrumentation – Summary of Aging Management Evaluation – LRA Table 3.1.2-1

The staff reviewed LRA Table 3.1.2-1 which summarizes the results of AMR evaluations for the nuclear boiler instrumentation component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.1.2.1.

3.1.2.3.2 Reactor Vessel, Internals, and Reactor Coolant System – Reactor Internals – Summary of Aging Management Evaluation – LRA Table 3.1.2-2

In LRA Table 3.1.2-2, the applicant stated that the nickel-alloy core shroud and core plate components exposed to reactor coolant and neutron flux are being managed for cracking due to SCC, IGSCC, and IASCC by the BWR Vessel Internals Program and Water Chemistry Program. The AMR line items cite generic note F, indicating that the material for the AMR line item component is not evaluated in the GALL Report.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environmental combination because nickel-alloy components exposed to reactor coolant and neutron flux are subject to cracking due to SCC, IGSCC, or IASCC, similar to the stainless steel components. The staff noted that the GALL Report recommends that stainless steel core shroud (GALL AMR item IV.B1-1) and core plate (GALL AMR item IV.B1-6) components exposed to reactor coolant be managed for cracking due to SCC, IGSCC, and/or IASCC. The staff further noted that the applicant is managing loss of material due to pitting and crevice corrosion for these components and are associated with LRA Table 3.1.1, item 3.1.1-47.

The staff noted that nickel-alloy components are corrosion resistant materials much like stainless steel and are also susceptible to many of the same aging effects and mechanisms such as cracking due to SCC, IGSCC, and/or IASCC. The staff's evaluation of the applicant's BWR Vessel Internals Program and Water Chemistry Program are documented in SER Sections 3.0.3.1.7 and 3.0.3.2.1, respectively. The staff noted that the Water Chemistry Program includes controls of chemistry parameters which create an environment that is not conducive for loss of material to occur. The staff finds the applicant's proposal to manage aging using the BWR Vessel Internals Program and Water Chemistry Program acceptable because: (1) the internals program follows the guidelines recommended by the BWRVIP, which includes stringent inspections, such as the use of EVT-1 or UT, and specific flaw evaluation and repair recommendations to facilitate post-inspection review; and (2) the applicant's use of the Water Chemistry Program creates an environment that is not conducive for cracking to occur.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.1.2-.2, the applicant stated that the stainless steel with stellite cladding core shroud and core plate (LPCI coupling), and jet pump assemblies components exposed to reactor coolant and neutron flux are being managed for cracking due to SCC, IGSCC, and IASCC, and loss of material due to pitting and crevice corrosion by the BWR Vessel Internals Program and Water Chemistry Program. The AMR line items cite generic note F, indicating that the material for the AMR line item component is not evaluated in the GALL Report.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because stainless steel with stellite cladding components exposed to reactor coolant and neutron flux are subject to cracking due to SCC, IGSCC, and/or IASCC, and loss of material due to pitting and crevice corrosion similar to the stainless steel components. The staff noted that the GALL Report recommends that stainless steel core shroud and core plate (LPCI coupling) (GALL AMR item IV.B1-3) and jet pump assemblies (GALL AMR item IV.B1-13) components exposed to reactor coolant be managed for cracking due to SCC, IGSCC, and/or IASCC. The staff also noted that the GALL Report recommends that stainless steel RVI components (GALL AMR item IV.B1-15) exposed to reactor coolant be managed for loss of material due to pitting and crevice corrosion.

The staff noted that stainless steel with stellite components are corrosion resistant materials much like stainless steel and are also susceptible to many of the same aging effects and mechanisms such as cracking due to SCC, IGSCC, and/or IASCC, and loss of material due to pitting and crevice corrosion. The staff's evaluation of the applicant's BWR Vessel Internals Program and Water Chemistry Program are documented in SER Sections 3.0.3.1.7 and 3.0.3.2.1, respectively. The staff noted that the Water Chemistry Program includes controls of chemistry parameters which create an environment that is not conducive for loss of material to occur. The staff finds the applicant's proposal to manage aging using the BWR Vessel Internals Program and Water Chemistry Program acceptable because: (1) the internals program follows the guidelines recommended by the BWRVIP, which includes stringent inspections, such as the use of EVT-1 or UT, and specific flaw evaluation and repair recommendations to facilitate post-inspection review; and (2) the applicant's use of the Water Chemistry Program creates an environment that is not conducive for cracking to occur.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.1.2-2, the applicant stated that nickel-alloy jet pump assemblies exposed to reactor coolant and neutron flux are being managed for loss of preload and stress relaxation by a TLAA. The AMR line item cites generic note H, which indicates that the aging effect is not addressed in the GALL Report for this component, material, and environment combination. TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1), and the staff's evaluation of the TLAA for this item is documented in SER Section 4.7.3.

In LRA Table 3.1.2-2, the applicant stated that stainless steel core shroud and core plate components exposed to reactor coolant and neutron flux are being managed for loss of preload and stress relaxation by a TLAA. The AMR line item cites generic note H, which indicates that the aging effect is not addressed in the GALL Report for this component, material, and environment combination. TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1), and the staff's evaluation of the TLAA for this item is documented in SER Section 4.2.7.

3.1.2.3.3 Reactor Vessel, Internals, and Reactor Coolant System – Reactor Pressure Vessel – Summary of Aging Management Evaluation – LRA Table 3.1.2-3

In LRA Table 3.1.2-3, the applicant stated that high-strength low alloy steel ASME Class 1 bolting (i.e., top head studs and nuts) with yield strength of 150 ksi or greater exposed to indoor air is being managed for loss of material due to general, pitting, and crevice corrosion by the Reactor Head Closure Studs Program. The AMR line items cite generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination.

The staff's evaluation of the Reactor Head Closure Studs Program is documented in SER Section 3.0.3.1.2. The staff noted that the Reactor Head Closure Studs Program manages loss of material for the reactor head closure studs, nuts, and washers using visual and volumetric inspections in accordance with ASME Code Section XI, Subsection IWA. The staff finds that the applicant's proposed program to manage loss of material for low alloy steel bolting with yield strength of 150 ksi or greater exposed to indoor air acceptable because the applicant will use inspection techniques that are in accordance with ASME Code Section XI, Subsection IWA, which are acceptable for detection of loss of material.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.4 Reactor Vessel, Internals, and Reactor Coolant System – Reactor Recirculation System – Summary of Aging Management Evaluation – LRA Table 3.1.2-4

The staff reviewed LRA Table 3.1.2-4 which summarizes the results of AMR evaluations for the reactor recirculation system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.1.2.1.

3.1.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the RCS, reactor vessel, and RVI components within the scope of license renewal and 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, as required by 10 CFR 54.21(a)(3).

3.2 Aging Management of Engineered Safety Features

This section of the SER documents the staff's review of the applicant's AMR results for the ESF components and component groups of:

- containment hydrogen recombiner system
- core spray system
- filtration, recirculation, and ventilation system
- high pressure coolant injection system
- hydrogen and oxygen analyzer system
- reactor core isolation cooling system
- residual heat removal system
- vacuum relief valve system

3.2.1 Summary of Technical Information in the Application

LRA Section 3.2 provides AMR results for the ESF components and component groups. LRA Table 3.2.1, "Summary of Aging Management Evaluations for the Engineered Safety Features," provides a summary comparison of its AMRs to those evaluated in the GALL Report for ESF components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included issue reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.2.2 Staff Evaluation

The staff reviewed LRA Section 3.2 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for ESF components within the scope of license renewal and 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, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit of AMPs to confirm the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to verify the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.2.2.1 and 3.2.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.2.2.3.

For components which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.2-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.2 and addressed in the GALL Report.

Table 3.2-1 Staff Evaluation for Engineered Safety Features System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel and stainless steel piping, piping components, and piping elements in the ECCS (3.2.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (See SER Section 3.2.2.2.1)
Steel with stainless steel cladding pump casing exposed to treated borated water (3.2.1-2)	Loss of material due to cladding breach	A plant-specific AMP is to be evaluated. Reference NRC IN 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks"	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.2.2.2.2)
Stainless steel containment isolation piping and components internal surfaces exposed to treated water (3.2.1-3)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.2.2.2.3)
Stainless steel piping, piping components, and piping elements exposed to soil (3.2.1-4)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.2.2.2.3)
Stainless steel and aluminum piping, piping components, and piping elements exposed to treated water (3.2.1-5)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.2.2.2.3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil (3.2.1-6)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Lubricating Oil Analysis and One-Time Inspection	Consistent with GALL Report (See SER Section 3.2.2.2.3)
Partially encased stainless steel tanks with breached moisture barrier exposed to raw water (3.2.1-7)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated for pitting and crevice corrosion of tank bottoms because moisture and water can egress under the tank due to cracking of the perimeter seal from weathering.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.2.2.2.3)
Stainless steel piping, piping components, piping elements, and tank internal surfaces exposed to condensation (internal) (3.2.1-8)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Periodic Inspection	Consistent with GALL Report (See SER Section 3.2.2.2.3)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil (3.2.1-9)	Reduction of heat transfer due to fouling	Lubricating Oil Analysis and One-Time Inspection	Yes	Lubricating Oil Analysis and One-Time Inspection	Consistent with GALL Report (See SER Section 3.2.2.2.4)
Stainless steel heat exchanger tubes exposed to treated water (3.2.1-10)	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.2.2.2.4)
Elastomer seals and components in the standby gas treatment system exposed to air – indoor uncontrolled (3.2.1-11)	Hardening and loss of strength due to elastomer degradation	A plant-specific AMP is to be evaluated.	Yes	Periodic Inspection	Consistent with GALL Report (See SER Section 3.2.2.2.5)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel high-pressure safety injection (HPSI) (charging) pump miniflow orifice exposed to treated borated water (3.2.1-12)	Loss of material due to erosion	A plant-specific AMP is to be evaluated for erosion of the orifice due to extended use of the centrifugal HPSI pump for normal charging.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.2.2.2.6)
Steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air – indoor uncontrolled (internal) (3.2.1-13)	Loss of material due to general corrosion and fouling	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.2.2.2.7)
Steel piping, piping components, and piping elements exposed to treated water (3.2.1-14)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.2.2.2.8)
Steel containment isolation piping, piping components, and piping elements internal surfaces exposed to treated water (3.2.1-15)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable (See SER Section 3.2.2.2.8)
Steel piping, piping components, and piping elements exposed to lubricating oil (3.2.1-16)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Lubricating Oil Analysis and One-Time Inspection	Consistent with GALL Report (See SER Section 3.2.2.2.8)
Steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil (3.2.1-17)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.2.2.2.9)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60 °C (140 °F) (3.2.1-18)	Cracking due to SCC and IGSCC	BWR Stress Corrosion Cracking and Water Chemistry	No	BWR Stress Corrosion Cracking and Water Chemistry	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to steam or treated water (3.2.1-19)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Flow-Accelerated Corrosion	Consistent with GALL Report
CASS piping, piping components, and piping elements exposed to treated water (borated or unborated) > 250 °C (482 °F) (3.2.1-20)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Not applicable	Not applicable to HCGS (See SER Section 3.2.2.1.1)
High-strength steel closure bolting exposed to air with steam or water leakage (3.2.1-21)	Cracking due to cyclic loading and SCC	Bolting Integrity	No	Not applicable	Not applicable to HCGS (See SER Section 3.2.2.1.1)
Steel closure bolting exposed to air with steam or water leakage (3.2.1-22)	Loss of material due to general corrosion	Bolting Integrity	No	Not applicable	Not applicable to HCGS (See SER Section 3.2.2.1.1)
Steel bolting and closure bolting exposed to air – outdoor (external), or air – indoor uncontrolled (external) (3.2.1-23)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	No	Bolting Integrity	Consistent with GALL Report (See SER Sections 3.2.2.1.2, 3.3.2.1.2, and 3.5.2.1.4)
Steel closure bolting exposed to air – indoor uncontrolled (external) (3.2.1-24)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity Program ASME Section XI, Subsection IWE 10 CFR Part 50, Appendix J	Consistent with GALL Report (See SER Sections 3.2.2.1.4 and 3.5.2.1.2)
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water > 60 °C (140 °F) (3.2.1-25)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-26)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Steel heat exchanger components exposed to closed-cycle cooling water (3.2.1-27)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water (3.2.1-28)	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Copper alloy piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water (3.2.1-29)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Stainless steel and copper alloy heat exchanger tubes exposed to closed-cycle cooling water (3.2.1-30)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
External surfaces of steel components including ducting, piping, ducting closure bolting, and containment isolation piping external surfaces exposed to air – indoor uncontrolled (external); condensation (external) and air – outdoor (external) (3.2.1-31)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping and ducting components and internal surfaces exposed to air – indoor uncontrolled (internal) (3.2.1-32)	Loss of material due to general corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable	Not applicable to HCGS (See SER Section 3.2.2.1.1)
Steel encapsulation components exposed to air – indoor uncontrolled (internal) (3.2.1-33)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable	Not applicable to HCGS (See SER Section 3.2.2.1.1)
Steel piping, piping components, and piping elements exposed to condensation (internal) (3.2.1-34)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report
Steel containment isolation piping and components internal surfaces exposed to raw water (3.2.1-35)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Steel heat exchanger components exposed to raw water (3.2.1-36)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Stainless steel piping, piping components, and piping elements exposed to raw water (3.2.1-37)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Stainless steel containment isolation piping and components internal surfaces exposed to raw water (3.2.1-38)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Periodic Inspection Fire Water System	Consistent with GALL Report (See SER Section 3.2.2.1.3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel heat exchanger components exposed to raw water (3.2.1-39)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Steel and stainless steel heat exchanger tubes (serviced by open-cycle cooling water) exposed to raw water (3.2.1-40)	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Copper alloy > 15% Zn piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water (3.2.1-41)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to HCGS
Gray cast iron piping, piping components, piping elements exposed to closed-cycle cooling water (3.2.1-42)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to HCGS
Gray cast iron piping, piping components, and piping elements exposed to soil (3.2.1-43)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to HCGS
Gray cast iron motor cooler exposed to treated water (3.2.1-44)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Selective Leaching of Materials	Consistent with GALL Report
Aluminum, copper alloy > 15% Zn and steel external surfaces, bolting, and piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-45)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Not applicable	Not applicable to BWRs

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel encapsulation components exposed to air with borated water leakage (internal) (3.2.1-46)	Loss of material due to general, pitting, crevice and boric acid corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable	Not applicable to BWRs
CASS piping, piping components, and piping elements exposed to treated borated water > 250 °C (482 °F) (3.2.1-47)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Not applicable	Not applicable to BWRs
Stainless steel or stainless-steel-clad steel piping, piping components, piping elements, and tanks (including safety injection tanks/accumulators) exposed to treated borated water > 60 °C (140 °F) (3.2.1-48)	Cracking due to SCC	Water Chemistry	No	Not applicable	Not applicable to BWRs
Stainless steel piping, piping components, piping elements, and tanks exposed to treated borated water (3.2.1-49)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Not applicable	Not applicable to BWRs
Aluminum piping, piping components, and piping elements exposed to air – indoor uncontrolled (internal/external) (3.2.1-50)	None	None	No	None	Consistent with GALL Report
Galvanized steel ducting exposed to air – indoor controlled (external) (3.2.1-51)	None	None	No	Not applicable	Not applicable to HCGS
Glass piping elements exposed to air – indoor uncontrolled (external), lubricating oil, raw water, treated water, or treated borated water (3.2.1-52)	None	None	No	None	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, copper alloy, and nickel-alloy piping, piping components, and piping elements exposed to air – indoor uncontrolled (external) (3.2.1-53)	None	None	No	None	Consistent with GALL Report (See SER Sections 2.3.3.10 and 3.3.2.3.10)
Steel piping, piping components, and piping elements exposed to air – indoor controlled (external) (3.2.1-54)	None	None	No	Not applicable	Not applicable to HCGS
Steel and stainless steel piping, piping components, and piping elements in concrete (3.2.1-55)	None	None	No	Not applicable	Not applicable to HCGS
Steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to gas (3.2.1-56)	None	None	No	None	Consistent with GALL Report
Stainless steel and copper alloy < 15% Zn piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-57)	None	None	No	Not applicable	Not applicable to BWRs

The staff's review of the ESF component groups followed several approaches. One approach, documented in SER Section 3.2.2.1, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.2.2.2, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.2.2.3, discusses the staff's review of AMR results for components the applicant indicated are not consistent with or not addressed in the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the ESF components is documented in SER Section 3.0.3.

3.2.2.1 AMR Results That Are Consistent with the GALL Report

In LRA Section 3.2.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects of ESF components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- BWR Stress Corrosion Cracking
- External Surfaces Monitoring
- Flow-Accelerated Corrosion
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- Periodic Inspection
- Selective Leaching of Materials
- Small-Bore Class 1 Piping Inspection
- TLAA
- Water Chemistry

LRA Tables 3.2.2-1 to 3.2.2-8 summarize AMRs for the ESF components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant had claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed a review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and that it had reviewed and accepted the identified exceptions to the GALL Report AMPs. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component applied to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff confirmed whether the AMR line item of the different component was applicable to the component under review and whether it had reviewed and accepted the exceptions to the GALL Report AMPs. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

LRA Tables 3.2.2-1 to 3.2.2-8 provide a summary of the AMR results for component types associated with the ESF. The summary information for each component type included intended function; material; environment; AERM; AMPs; GALL Report, Volume 2 item; cross reference to LRA Table 3.2.1; and generic and plant-specific notes related to consistency with the GALL Report.

The staff reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, it did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs.

On the basis of its review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.2.1, the applicant’s references to the GALL Report are acceptable and no further evaluation is required.

The staff notes that in LRA Tables 3.2.2-4 and 3.2.2-8 there are AMR line items for carbon steel tanks exposed to treated water and gray cast iron tanks exposed to lubricating oil. The staff also notes that the LRA does not have a line item for the tank material exposed to an air or wetted gas internal environment as would occur when the tank is partially full. The staff further notes that in each instance, the LRA line items manage the aging of the tank internals using the appropriate chemistry controlling AMP, Water Chemistry and Lubricating Oil programs respectively, and the One-Time Inspection Program. The staff finds the existing line items acceptable because the chemistry program will minimize contaminant concentrations and thus mitigate loss of material due to various corrosion mechanisms for tank internal surfaces at the fluid to air transition zone, and the One-Time Inspection Program will provide reasonable assurance that an aging effect is not occurring or that the aging effect is occurring slowly enough as to not affect a components intended function.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.2.1, item 3.2.1-20 addresses loss of fracture toughness due to thermal aging embrittlement in CASS piping, piping components, and piping elements exposed to treated water (borated or unborated) greater than 250 °C (482 °F). The applicant stated that this line item is not applicable because there are no CASS piping, piping components, or piping elements subject to treated water greater than 250 °C (482 °F) in the ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include CASS piping, piping components, and piping elements exposed to treated water (borated or unborated) greater than 250 °C (482 °F). The staff also reviewed the applicant's UFSAR and noted that Table 6.1-2 states that core spray and RHR system LPCI valves can be constructed of CASS material. By letter dated August 18, 2010, the staff issued RAI 3.2.1.20-01 requesting that the applicant state whether any of the core spray and RHR system LPCI RCPB valves or valves located inside the primary containment are constructed of CASS material or exposed to a temperature greater 250 °C (482 °F). In its response dated September 1, 2010, the applicant stated that it conducted a confirmatory review and found that there are no valves constructed of CASS that are exposed to an operating environment greater 250 °C (482 °F) during normal operation in the core spray and RHR LPCI systems. The staff finds the applicant's response acceptable because it performed a confirmatory review for the specific material and temperature limit as requested by the staff, and no valves constructed of CASS material exposed to an operating environment greater 250 °C (482 °F) during normal operation exists in the core spray and RHR LPCI systems. The staff confirmed that no in-scope CASS piping, piping components, and piping elements exposed to treated water (borated or unborated) greater than 250 °C (482 °F) are present in the ESF systems and, therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-21 addresses high-strength steel closure bolting exposed to air with steam or water leakage in the ESF systems. The GALL Report recommends the use of GALL AMP XI.M18, "Bolting Integrity," to manage cracking due to cyclic loading or SCC for this component group. The applicant stated that this item is not applicable because there is no high-strength closure bolting in the ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include high-strength steel closure bolting exposed to air with steam or water leakage. The staff reviewed the applicant's UFSAR and confirmed that no in-scope high-strength steel closure bolting exposed to air with steam or water leakage is present in the ESF systems and, therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-22 addresses steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends the use of GALL AMP XI.M18, "Bolting Integrity," to manage loss of material due to general corrosion for this component group. The applicant stated that this item is not applicable because the AMR methodology for steel closure bolting predicts pitting and crevice corrosion, in addition to general corrosion, and as a result, item 3.2.1-23 is credited for this component instead. The staff evaluated the applicant's claim and found it acceptable because the applicant: (1) identified the loss of material due to general, pitting, and crevice corrosion which is a more conservative approach than the loss of material due to general corrosion for this component group and (2) has credited an alternate Table 1, item 3.2.1-23 to manage this component group.

LRA Table 3.2.1, item 3.2.1-32 addresses loss of material due to general corrosion in steel piping and ducting components and internal surfaces exposed internally to uncontrolled indoor air. The applicant stated that this line item is not applicable because AMR methodology assumes internal surfaces are exposed to an air/gas-wetted environment, which includes condensation, and as a result, item 3.2.1-34 is credited for this component instead. The staff evaluated the applicant's claim and found it acceptable because the applicant credited an alternate item 3.2.1-34 to manage this component group, which is being managed for loss of material due to pitting and crevice corrosion, in addition to general corrosion.

LRA Table 3.2.1, item 3.2.1-33 addresses loss of material due to general, pitting, and crevice corrosion in steel encapsulation components exposed internally to uncontrolled indoor air. The applicant stated that this line item is not applicable because there are no steel encapsulation components exposed to indoor uncontrolled air in the ESF system. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF system that include steel encapsulation components exposed internally to uncontrolled indoor air. The staff also reviewed the applicant's UFSAR and confirmed that no in-scope steel encapsulation components exposed internally to uncontrolled indoor air are present in the ESF system and, therefore, the staff finds the applicant's determination acceptable.

3.2.2.1.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Table 3.2.1, item 3.2.1-23 addresses steel closure bolting exposed to air – outdoor (external) or air – indoor uncontrolled (external) which are being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the ASME Section XI, Subsection IWE Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to ensure that the aging effects are adequately managed. In LRA Table 3.5.2-7 (Primary Containment), the applicant aligned AMR results for carbon and low alloy steel bolting exposed to air – indoor with item 3.2.1-23. The applicant cited generic note E, indicating that the AMR result is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

The staff reviewed the applicant's ASME Section XI, Subsection IWE Program and its evaluation is documented in SER Section 3.0.3.2.14. During its review of AMR result lines associated with components for which the GALL Report recommends the Bolting Integrity Program, the staff noted that several other programs were identified to manage aging for bolting in the LRA. The staff issued RAI B.2.1.12-01 requesting that the applicant explain why programs other than the Bolting Integrity Program were credited to manage aging for structural bolting.

In it response, which is evaluated in SER Section 3.0.3.2.4, the applicant added a number of AMR result lines, including some associated with LRA Table 3.2.1, item 3.2.1-23. The added AMR result lines credit the Bolting Integrity Program, in addition to the previously credited program, to manage loss of material due to general, pitting, and crevice corrosion and cite generic note B, indicating that the results are consistent with the GALL Report for component, material, environment, and aging effect, but the AMP takes some exception(s) to the GALL Report. The staff finds the applicant's proposed combination of programs acceptable to manage aging for these components because: (1) the programs include visual inspections of bolting which are capable of detecting loss of preload, (2) the use of the Bolting Integrity Program is consistent with the recommendations in the GALL Report, and (3) supplementing the inspections performed by the Bolting Integrity Program with inspections performed by the ASME Section XI, Subsection IWE Program provides a more comprehensive approach to monitoring aging for these components.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.1.3 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

LRA Table 3.2.1, item 3.2.1-38 addresses stainless steel containment isolation piping and components internal surfaces exposed to raw water being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling. The LRA credits the Fire Water System Program for stainless steel flow elements, strainers, electric heaters, piping and fittings, and valves bodies in the fire protection system. The GALL Report recommends GALL AMP XI.M20, "Open-Cycle Cooling Water System Program," to ensure that these aging effects are adequately managed. The AMR line items cite generic note E. The LRA also cites plant-specific note 5, indicating that the Fire Water System program is substituted to manage the aging effect applicable to this component type, material, and environment combination.

GALL AMP XI.M20 relies on implementation of the recommendations of GL 89-13, which includes using preventive measures (i.e., water chemistry control), periodic visual inspections, and performance testing to manage these aging effects. In its review of components associated with item 3.2.1-38 for which the applicant cited generic note E, the staff noted that the applicant credited the Fire Water System Program to manage aging for these stainless steel components in LRA Table 3.3.2-10.

The staff reviewed the applicant's Fire Water System Program and its evaluation is documented in SER Section 3.0.3.2.8. The staff noted that the Fire Water System Program proposes to manage the aging effects of the stainless steel components in the fire protection system through the use of preventive measures (including non-intrusive volumetric examinations), periodic inspections, performance monitoring, and performance testing to ensure that aging effects are managed and that wall thickness is maintained within acceptable limits. The staff finds the applicant's proposed program acceptable to manage aging for these components because: (1) the Fire Water System Program includes preventive measures to detect aging prior to loss of function, performance monitoring, and periodic visual inspections which are as effective as the GALL Report recommended AMP at managing aging for these components; and (2) the components are in the fire protection system and are not within the scope of GL 89-13 and, therefore, GALL AMP XI.M20 would not apply.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.2.1, item 3.2.1-38 addresses stainless steel containment isolation piping and component internal surfaces exposed to raw water which are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling. The LRA credits the Periodic Inspection Program to manage aging for components in the equipment and floor drainage and radwaste systems. The GALL Report recommends GALL AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The AMR line items cite generic note E, which indicate that the line item is consistent with the GALL Report for the material, environment, and aging effect, but a different AMP is credited.

GALL AMP XI.M20 recommends preventive measures including proper selection of materials and coatings, periodic flushes and cleaning, and raw water chemistry control, as well as visual inspections and NDE testing for components exposed to open-cycle cooling water. Open-cycle cooling water is water that transfers heat from safety-related components to the ultimate heat sink.

The staff reviewed the applicant's Periodic Inspection Program and its evaluation is documented in SER Section 3.0.3.3.2. The staff noted that the Periodic Inspection Program includes periodic visual inspections of components and ultrasonic wall thickness measurements to detect loss of material and fouling. The staff also notes that the equipment and floor drainage and radwaste systems do not contain safety-related components exposed to open-cycle cooling water, so use of the Open-Cycle Cooling Water Program would not be appropriate. The staff finds the applicant's use of the Periodic Inspection Program acceptable for managing aging of these components because it performs periodic visual inspections and wall thickness measurements that are appropriate to detect loss of material and fouling.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.1.4 Loss of Preload Due to Thermal Effects, Gasket Creep, and Self-Loosening

LRA Table 3.2.1, item 3.2.1-24 addresses steel closure bolting exposed to air – indoor uncontrolled (external) which is being managed for loss of preload due to thermal effects, gasket creep, and self-loosening. The LRA credits the ASME Section XI, Subsection IWE Program and the 10 CFR Part 50, Appendix J Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to ensure that the aging effects are adequately managed. In LRA Table 3.5.2-7 (Primary Containment), the applicant aligned AMR results for carbon and low alloy steel bolting exposed to air – indoor with item 3.2.1-24. The applicant cited generic note E, indicating that the AMR result is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

The staff reviewed the applicant's ASME Section XI, Subsection IWE Program and the 10 CFR Part 50, Appendix J Program and its evaluations are documented in SER Sections 3.0.3.2.14, and 3.0.3.1.16, respectively. During its review of AMR result lines associated with components for which the GALL Report recommends the Bolting Integrity Program, the staff noted that several other programs were identified to manage aging for bolting in the LRA. The staff issued RAI B.2.1.12-01 requesting that the applicant explain why programs other than the Bolting Integrity Program were credited to manage aging effects in structural bolting.

In it response, which is evaluated in SER Section 3.0.3.2.4, the applicant added a number of AMR result lines, including some associated with LRA Table 3.2.1, item 3.2.1-24. The added AMR result lines credit the Bolting Integrity Program, in addition to the previously credited program, to manage loss of preload due to thermal effects, gasket creep, and self-loosening and cite Note B, indicating that the results are consistent with the GALL Report for component, material, environment, and aging effect, but the AMP takes some exception(s) to the GALL

Report. The staff finds the applicant's proposed combination of programs acceptable to manage aging for these components because: (1) the programs include visual inspections of bolting which are capable of detecting loss of preload, (2) the use of the Bolting Integrity Program is consistent with the recommendations in the GALL Report, and (3) supplementing the inspections performed by the Bolting Integrity Program with inspections performed by the ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J Program provides a more comprehensive approach to monitoring aging for these components.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

LRA Section 3.2.2.2 provides further evaluation of aging management as recommended by the GALL Report for the ESF components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to cladding
- loss of material due to pitting and crevice corrosion
- reduction of heat transfer due to fouling
- hardening and loss of strength due to elastomer degradation
- loss of material due to erosion
- loss of material due to general corrosion and fouling
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which further evaluation is recommended, the staff audited and reviewed the applicant's evaluations to determine whether they adequately address those issues. In addition, the staff reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.2.2.2. The staff's review of the applicant's further evaluation follows.

3.2.2.2.1 Cumulative Fatigue Damage

LRA Section 3.2.2.2.1 addresses the applicant's AMR basis for managing cumulative fatigue damage in ESF system components that were designed to applicable design analysis criteria in the ASME Code Section III, Articles NC-3000 or ND-3000 (as applicable to Code Class 2 or 3 components, respectively) or in the American National Standards Institute (ANSI) B31.1 Code, and for which implicit fatigue analyses were required. In this LRA Section, the applicant stated that the evaluation of fatigue is a TLAA as defined in 10 CFR 54.3, and that the TLAAs are evaluated in accordance with the TLAA acceptance criteria in 10 CFR 54.21(c)(1). The applicant stated that metal fatigue as a TLAA for the HPCI, RCIC, and RHR systems is discussed in LRA Section 4.3.

In LRA Table 3.2.1, the applicant stated that AMR item 3.2.1-1 for managing of cumulative fatigue damage for the applicant's ESF components is consistent with the staff's AMR item recommendations in AMR item 1 of Table 2 in the GALL Report, Volume 1, Revision 1. The applicant stated that, for these AMRs, cumulative fatigue damage in the components will be managed using a TLAA and that LRA Section 4.3.4 describes and evaluates implicit fatigue analysis-based TLAAs for these components.

The staff reviewed LRA Section 3.2.2.2.1 against the criteria in SRP-LR Section 3.2.2.2.1, which states that fatigue of ESF components is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1) and in accordance with the staff's recommended acceptance criteria and review procedures for reviewing these TLAAs in SRP-LR Section 4.3, "Metal Fatigue Analysis." The staff also reviewed LRA Section 3.2.2.2.1 and the AMRs discussed in this section against the staff's AMR items for evaluating cumulative fatigue damage in BWR ESF designs, as given in the GALL Report.

With regard to the applicant's metal fatigue AMR item 3.2.1-1, the staff noted that AMR item 1 in Table 2 of the GALL Report, Volume 1 and AMR item V.D2-32 in the GALL Report, Volume 2 identify that cumulative fatigue damage is an applicable aging effect for steel and stainless steel piping, piping components, and piping elements in the ECCS. The staff also noted that these GALL AMRs recommend that the TLAA on metal fatigue be used to manage the impact of cumulative fatigue damage in these components. The staff noted that, in conformance with this recommendation, the applicant included an applicable line item in LRA Tables 3.2.2-4, 3.2.2-6, and 3.2.2-7 for piping, piping components, and piping elements that received ASME Code Section III CUF or ANSI B31.1 design code analysis calculations. The staff noted that the applicant credited the TLAA analysis in LRA Section 4.3.4 with the management of cumulative fatigue damage in these components. The staff found that the applicant's AMR assessment was in conformance with the recommendations both in the SRP-LR and in AMR item 1 of the GALL Report, Volume 1, Table 2 and AMR item V.D2-32 in the GALL Report, Volume 2. Based on this review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of piping, piping components, and piping elements to be acceptable because it is in conformance with the recommendations in SRP-LR Section 3.2.2.2.1 and the GALL AMR items that are invoked by this SRP-LR section. The staff evaluates the TLAA analysis for the support skirt and attachment welds component in SER Section 4.3.4.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.1 criteria. For those items that apply to LRA Section 3.2.2.2.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.2 Loss of Material Due to Cladding

LRA Section 3.2.2.2.2 refers to Table 3.2.1, item 3.2.1-2 and addresses loss of material due to cladding. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.2.2.2.2 states that loss of material due to cladding breach could occur for PWR steel pump casing with stainless steel cladding exposed to treated borated water. SRP-LR Table 3.2-1 identifies item 2 applicable to PWRs.

The staff verified that SRP-LR Section 3.2.2.2.2 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR steel with stainless steel cladding pump casing exposed to treated borated water.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.2.2.2.2 do not apply to HCGS because the guidance is applicable to PWRs.

3.2.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.2.2.2.3 against the criteria in SRP-LR Section 3.2.2.2.3.

(1) LRA Section 3.2.2.2.3.1 is associated with LRA Table 3.2.1, item 3.2.1-3 and addresses stainless steel containment isolation piping and components internal surfaces exposed to treated water which are being managed for loss of material due to pitting and crevice corrosion. The applicant stated that this line item is not applicable because its ESF system stainless steel containment isolation piping, piping components, and piping elements exposed to treated water are evaluated with other Class 1 components under LRA Table 3.1.1, item 3.1.1-15. The applicant also stated that the above listed hardware is addressed in LRA Section 3.1.2.2.2, item 3, which implements the Water Chemistry and the One-Time Inspection Programs to ensure effective aging management practices. The staff reviewed LRA Sections 2.3.2 and 3.2, and confirmed that the applicant's LRA addresses loss of material due to pitting and crevice corrosion of internal surfaces of stainless steel containment isolation piping, piping components, and piping elements exposed to treated water for ESF systems using item 3.1.1-15 and that loss of material is managed with the Water Chemistry and One-Time Inspection Programs as recommended in the GALL Report. Based on its review of the LRA and UFSAR, the staff confirmed that loss of material due to pitting and crevice corrosion of internal surfaces of stainless steel containment isolation piping, piping components, and piping elements exposed to treated water in the ESF systems is managed under an alternate SRP-LR designation with similar acceptance criteria which are consistent with the GALL Report and, therefore, the staff finds the applicant's determination acceptable.

(2) LRA Section 3.2.2.2.3.2 refers to Table 3.2.1, item 3.2.1-4 and addresses stainless steel piping, piping components, and piping elements exposed to soil. The applicant stated that this aging effect is not applicable because HCGS does not have any stainless steel piping, piping components, or piping elements exposed to soil in the ESF systems.

    SRP-LR Section 3.2.2.2.3.2 states that loss of material from pitting and crevice corrosion could occur for stainless steel piping, piping components, and piping elements exposed to soil.

The staff reviewed the applicant's UFSAR and finds that SRP-LR Section 3.2.2.2.3, item 2 is not applicable to HCGS because HCGS does not have any stainless steel piping, piping components, or piping elements exposed to soil in the ESF systems and the staff guidance in this SRP-LR section is only applicable to BWRs in the ESF system with stainless steel piping, piping components, or piping elements exposed to soil.

(3) LRA Section 3.2.2.2.3 is referenced by LRA Table 3.2.1, item 3.2.1-5 and addresses stainless steel and aluminum piping, piping components, and elements exposed to treated water which are being managed for loss of material due to pitting and crevice corrosion by the Water Chemistry and One-Time Inspection Programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be implemented to verify the effectiveness of the Water Chemistry Program to manage the loss of material due to pitting and crevice corrosion in stainless steel piping, piping components, and piping elements and tanks exposed to treated water in the containment hydrogen recombiner system, core spray system, HPCI system, RCIC system, and RHR system.

The staff reviewed LRA Section 3.2.2.2.3, item 3 against the criteria in SRP-LR Section 3.2.2.2.3, item 3, which states that: (1) loss of material due to pitting and crevice corrosion could occur for BWR stainless steel and aluminum piping, piping components, and piping elements exposed to treated water; (2) the existing AMP relies on monitoring and control of water chemistry to mitigate corrosion; and (3) control of water chemistry does not preclude corrosion at locations of stagnant flow conditions. The effectiveness of the water chemistry program, therefore, should be verified using a one-time inspection to ensure that corrosion does not occur. The GALL Report recommends a one-time inspection of select components at susceptible locations as an acceptable method to verify the effectiveness of the Water Chemistry Program and ensure that an aging effect is not occurring or is progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. The staff finds the combination of programs acceptable to manage aging for these components because the programs: (1) provide for periodic sampling of reactor coolant to maintain contaminants at acceptable limits to preclude loss of material due to pitting and crevice corrosion; and (2) will perform one-time inspections of stainless steel piping components, piping elements, and tanks exposed to treated water.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.3, item 3 criteria. For those line items that apply to LRA Section 3.2.2.2.3, item 3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(4) LRA Section 3.2.2.2.3.4 is associated with Table 3.2.1, item 3.2.1-6 and addresses stainless steel and copper alloy piping, piping components, piping elements, and heat exchangers exposed to lubricating oil in the HPCI system and RCIC system, which are being managed for loss of material due to pitting and crevice corrosion by the Lubricating Oil Analysis and One-Time Inspection programs. The applicant addressed the further evaluation requirements by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program.

The staff reviewed LRA Section 3.2.2.2.3.4 against the criteria in SRP-LR Section 3.2.2.2.3, item 4, which states that loss of material due to pitting and crevice corrosion could occur for stainless steel and copper alloy piping, piping components, piping elements, and heat exchangers exposed to lubricating oil. The SRP-LR also states that the existing program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's Lubricating Oil Analysis and One-Time Inspection Programs and their evaluations are documented in SER Sections 3.0.3.2.13 and 3.0.3.1.11, respectively. In its review of components associated with LRA item 3.2.1-6, the staff finds the applicant's proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection Programs acceptable because: (1) the applicant will perform sufficient inspections for each material-environment combination to provide an overall assessment of any aging degradation that may be occurring; (2) the selection of inspections will consider materials, operating environments, industry and plant-specific operating experience, engineering evaluations of equipment performance, and susceptibility to aging due to time in service, severity of operating conditions, and lowest design margins; (3) recurring surveillance and maintenance activities provides the ability to detect aging of the material-environment combination prior to loss of function; and (4) inspection results will be trended.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.3, item 4 criteria. For those line items that apply to LRA Section 3.2.2.2.3.4, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(5) LRA Section 3.2.2.2.3.5 refers to Table 3.2.1, item 3.2.1-7 and addresses partially encased stainless steel tanks with breached moisture barrier exposed to raw water. The applicant stated that this aging effect is not applicable because HCGS does not have any partially encased stainless steel tanks in the ESF system.

SRP-LR Section 3.2.2.2.3.5 states that loss of material from pitting and crevice corrosion could occur for partially encased stainless steel tanks exposed to raw water due to cracking of the perimeter seal from weathering.

The staff reviewed the applicant's UFSAR and finds that SRP-LR Section 3.2.2.2.3, item 5 is not applicable to HCGS because HCGS does not have any partially encased stainless steel tanks exposed to raw water in the ESF systems and the staff guidance in this SRP-LR section is only applicable to BWRs in the ESF system with partially encased stainless steel tanks with breached moisture barrier exposed to raw water.

(6) LRA Section 3.2.2.2.3, item 6, referenced by LRA Table 3.2.1, item 3.2.1-8, addresses stainless steel piping, piping components, piping elements, and tanks exposed to wetted air and gas, which are being managed for loss of material due to pitting and crevice

corrosion by the Periodic Inspection Program. The applicant addressed the further evaluation criteria by stating that the Periodic Inspection Program includes visual inspections and nondestructive volumetric examination of external and internal surfaces of non-steel components to ensure that environmental conditions are not causing material degradation.

The staff reviewed LRA Section 3.2.2.2.3, item 6 against the criteria described in SRP-LR Section 3.2.2.2.3, item 6, which states that loss of material due to pitting and crevice corrosion could occur for stainless steel piping, piping components, piping elements, and tanks exposed to internal condensation. It continues by stating that the GALL Report recommends further evaluation of a plant-specific AMP and that the acceptance criteria are described in Branch Technical Position RSLB-1.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. In its review of components associated with item 3.2.1-8, the staff finds the applicant's proposal to manage aging using the Periodic Inspection Program acceptable because visual inspections and nondestructive volumetric examinations can detect the loss of material due to pitting and crevice corrosion, which will ensure that existing environmental conditions are not causing material degradation that could result in a loss of the component's intended function.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.2.2.2.3, item 6 criteria. For those items that apply to LRA Section 3.2.2.2.3, item 6, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on a review of the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.3 criteria. For those line items that apply to LRA Section 3.2.2.2.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.4 Reduction of Heat Transfer Due to Fouling

The staff reviewed LRA Section 3.2.2.2.4 against the criteria in SRP-LR Section 3.2.2.2.4.

(1) LRA Section 3.2.2.2.4.1 is associated with Table 3.2.1, item 3.2.1-9 and addresses steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil in the HPCI, RCIC, and the closed-cycle cooling water systems, which are being managed for reduction of heat transfer due to fouling by the Lubricating Oil Analysis and One-Time Inspection Programs. The applicant addressed the further evaluation requirements by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program.

The staff reviewed LRA Section 3.2.2.2.4.1 against the criteria in SRP-LR Section 3.2.2.2.4, item 1, which states that reduction of heat transfer due to fouling could occur for steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil. The SRP-LR also states that the existing program relies on monitoring and control of lube oil chemistry to mitigate reduction of heat transfer due to fouling. However, control of lube oil chemistry may not always have been adequate to preclude fouling. Therefore, the effectiveness of lube oil chemistry control should be verified to ensure that fouling does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

The staff's evaluation of the applicant's Lubricating Oil Analysis Program and One-Time Inspection Program is documented in SER Sections 3.0.3.2.13 and 3.0.3.1.11, respectively. In its review of components associated with Table 3.2.1, item 3.2.1-9, the staff finds the applicant's proposal to manage aging using the above programs acceptable because the Lubricating Oil Analysis Program provides for periodic sampling of lubricating oil to maintain contaminants at acceptable limits to preclude loss of heat transfer due to fouling. In addition, the One-Time Inspection Program will include a sample of susceptible heat exchanger components in low or stagnant flow areas to verify the effectiveness of the Lubricating Oil Analysis Program.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.4, item 1 criteria. For those line items that apply to LRA Section 3.2.2.2.4.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.2.2.2.4, item 2 is associated with Table 3.2.1, item 3.2.1-10 and addresses stainless steel heat exchanger tubes exposed to treated water. The GALL Report recommends the Water Chemistry and One-Time Inspection programs to manage reduction of heat transfer for this component group. The applicant stated that this item is not applicable because, other than the RHR system, HCGS has no in-scope stainless steel heat exchanger tubes exposed to treated water in the ESF systems, and that the stainless steel heat exchanger components in the RHR system have been evaluated with the closed-cycle cooling water system components in Table 3.3.1, item 3.3.1-3.

The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include stainless steel heat exchanger tubes exposed to treated water in the ESF systems. The staff also reviewed the UFSAR and confirmed that, other than the RHR system, there are no in-scope heat exchangers constructed of stainless steel exposed to treated water in the ESF systems, and these components in the RHR system are further evaluated in LRA Section 3.3.2.2.2, therefore, the staff finds the applicant's determination acceptable.

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.4 criteria. For those line items that apply to LRA Section 3.2.2.2.4, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

The staff reviewed LRA Section 3.2.2.2.5 against the criteria in SRP-LR Section 3.2.2.2.5.

LRA Section 3.2.2.2.5 refers to Table 3.2.1, item 3.2.1-11 and addresses elastomer seals and components (door seals and flexible connections) in the filtration, recirculation, and ventilation system exposed to air – indoor uncontrolled or to an air/gas – wetted environment. The applicant stated that hardening and loss of strength in these components will be managed by the Periodic Inspection Program. The applicant addressed the further evaluation requirement by stating that the Periodic Inspection Program is used to manage aging effects of components that are not covered by other AMPs, including external and internal surfaces of non-steel components, and that the Periodic Inspection Program includes visual inspections and physical manipulation of elastomer components.

The staff reviewed LRA Section 3.2.2.2.5 against the criteria in SRP-LR Section 3.2.2.2.5, which states that hardening and loss of strength due to elastomer degradation could occur in elastomer seals and components associated with the BWR standby gas treatment system ductwork and filters exposed to air – indoor uncontrolled. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

The staff reviewed a description of the applicant's filtration, recirculation, and ventilation system in LRA Section 2.3.2.4 and in the applicant's UFSAR Section 6.8. The staff noted that the system is an ESF with intended functions equivalent to standby gas treatment systems at other BWRs. On this basis, the staff found the applicant's alignment of the filtration, recirculation, and ventilation system with item 3.2.1-11 to be acceptable.

The staff reviewed the applicant's Periodic Inspection Program, and its evaluation is documented in SER Section 3.0.3.3.2. In its review of components associated with LRA item 3.3.1-11, for which the applicant assigned generic note E, the staff noted that the Periodic Inspection Program is a plant-specific program that proposes to detect the aging of elastomer door seals and flexible connections through the use of visual inspections and physical manipulations. The staff finds the applicant's proposal to manage aging using the Periodic Inspection Program acceptable because the program performs visual inspections and physical manipulations that are capable of detecting hardening and loss of strength in elastomer components; and the program initiates corrective actions, implemented through the applicant's corrective action program, if indications of age-related degradation are found.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.2.2.2.5 criteria. For those line items that apply to LRA Section 3.2.2.2.5, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.6 Loss of Material Due to Erosion

LRA Section 3.2.2.2.6 refers to Table 3.2.1, item 3.2.1-12 and addresses loss of material due to erosion. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.2.2.2.6 states that loss of material due to erosion could occur in the stainless steel HPSI pump miniflow recirculation orifice exposed to treated borated water. SRP-LR Table 3.2-1 identifies item 12 applicable to PWRs.

The staff verified that SRP-LR Section 3.2.2.2.6 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR stainless steel HPSI pump miniflow orifices exposed to treated borated water.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.2.2.2.6 do not apply to HCGS because the guidance is applicable to PWRs.

3.2.2.2.7 Loss of Material Due to General Corrosion and Fouling

The staff reviewed LRA Section 3.2.2.2.7 against the criteria in SRP-LR Section 3.2.2.2.7.

LRA Section 3.2.2.2.7 is associated with Table 3.2.1, item 3.2.1-13 and addresses steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to indoor uncontrolled air which are being managed for loss of material due to general corrosion and fouling. The applicant stated that this line item is not applicable because it has no steel spray nozzles in its ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2 and confirmed that the applicant's LRA does not have any AMR results for the ESF systems that include steel spray nozzles. The staff also reviewed the applicant's UFSAR and confirmed that no in-scope steel spray nozzles are present in the ESF systems and, therefore, the staff finds the applicant's determination acceptable.

Based on the above, the staff concludes that SRP-LR Section 3.2.2.2.7 criteria do not apply.

3.2.2.2.8 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.2.2.2.8 against the criteria in SRP-LR Section 3.2.2.2.8.

(1) LRA Section 3.2.2.2.8, item 1, referenced by LRA Table 3.2.1, item 3.2.1-14 and addresses steel piping, piping components, and piping elements exposed to treated water which are being managed for loss of material due to general, pitting, and crevice corrosion by the Water Chemistry and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will implement a One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage loss of material due to general, pitting, and crevice corrosion of steel piping, piping components, and elements and tanks exposed to treated water at susceptible locations (containment hydrogen recombiner, core spray, HPCI, RCIC, and RHR systems).

    The staff reviewed LRA Section 3.2.2.2.8, item 1 against the criteria in SRP-LR Section 3.2.2.2.8, item 1, which states that: (1) loss of material due to general, pitting, and crevice corrosion could occur for BWR steel piping, piping components, and piping elements exposed to treated water; (2) the existing AMP relies on monitoring and control of water chemistry to mitigate corrosion; and (3) control of water chemistry does not preclude corrosion at locations of stagnant flow conditions. The effectiveness of the water chemistry program, therefore, should be verified using a one-time inspection to ensure that corrosion does not occur. The GALL Report recommends a one-time inspection of select components at susceptible locations as an acceptable method to verify the effectiveness of the Water Chemistry Program and ensure that an aging effect is not occurring or is progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. The staff finds this combination of programs acceptable to manage aging for these components because the programs: (1) provide for periodic sampling of treated water to maintain contaminants at acceptable limits to preclude loss of material due to general, pitting, and crevice corrosion; and (2) will perform one-time inspections of steel, piping components, piping elements, and tanks exposed to treated water.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.8, item 1 criteria. For those line items that apply to LRA Section 3.2.2.2.8, item 1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.2.2.2.8, item 2, referenced by LRA Table 3.2.1, item 3.2.1-15, addresses steel containment isolation piping, piping components, and piping elements exposed to treated water. The GALL Report, Table 3.2.1, item 3.2.1-15 recommends the water chemistry and one-time inspection programs to manage the loss of material on the internal surfaces due to general, pitting, and crevice corrosion for this component group. The applicant stated that this item was not applicable because the related components in the ESF systems are evaluated with other Class 1 components, as addressed in Table 3.1.1, item 3.1.1-13 and with other non-reactor coolant pressure boundary components, as addressed in Table 3.2.1, item 3.2.1-14. The staff evaluated the applicant's claim and found it acceptable because the comparable components in the ESF systems reference either Table 3.1.1, item 3.1.1-13 or Table 3.2.1, item 3.2.1-14, which are further evaluated in SER Section 3.1.2.2.2, item 2 and Section 3.2.2.2.8, item 1, respectively. In addition, both these items use the Water Chemistry and One-Time Inspection programs, which are the same as those recommended for Table 3.2.1, item 3.2.1-15.

(3) LRA Section 3.2.2.2.8.3 is associated with Table 3.2.1, item 3.2.1-16 and addresses steel piping, piping components, and piping elements exposed to lubricating oil in the HPCI and RCIC systems, which are being managed for loss of material due to general, pitting, and crevice corrosion by the Lubricating Oil Analysis and One-Time Inspection programs. The applicant addressed the further evaluation requirements by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program.

The staff reviewed LRA Section 3.2.2.2.8.3 against the criteria in SRP-LR Section 3.2.2.2.8, item 3, which states that loss of material due to general, pitting, and crevice corrosion could occur for steel piping, piping components, and piping elements exposed to lubricating oil. The SRP-LR also states that the existing program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's Lubricating Oil Analysis and One-Time Inspection programs and their evaluations are documented in SER Sections 3.0.3.2.13 and 3.0.3.1.11, respectively. In its review of components associated with LRA item 3.2.1-16, the staff finds the applicant's proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection programs acceptable because: (1) the applicant will perform sufficient inspections for each material-environment combination to provide an overall assessment of any aging degradation that may be occurring; (2) the selection of inspections will consider materials, operating environments, industry and plant-specific operating experience, engineering evaluations of equipment performance, and susceptibility to aging due to time in service, severity of operating conditions, and lowest design margins; (3) recurring surveillance and maintenance activities provides the ability to detect aging of the material-environment combination prior to loss of function; and (4) inspection results will be trended.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.8, item 3 criteria. For those line items that apply to LRA Section 3.2.2.2.8.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.8 criteria. For those line items that apply to LRA Section 3.2.2.2.8, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

LRA Section 3.2.2.2.9 refers to Table 3.2.1, item 3.2.1-17 and addresses loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion. The applicant stated that this aging effect is not applicable because HCGS does not have any steel (with or without coating or wrapping) piping, piping components, or piping elements buried in soil in the ESF systems.

SRP-LR Section 3.2.2.2.9 states that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion could occur for steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil.

The staff reviewed the applicant's UFSAR and finds that SRP-LR Section 3.2.2.2.9 is not applicable to HCGS because HCGS does not have any steel (with or without coating or wrappings) piping, piping components, or piping elements buried in soil in the ESF systems and the staff guidance in this SRP-LR section is only applicable to BWRs in the ESF system with steel (with or without coating or wrappings) piping, piping components, or piping elements buried in soil.

3.2.2.2.10 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA program.

3.2.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.2.2-1 through 3.2.2-8, the staff reviewed additional details of AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.2.2-1 through 3.2.2-8, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information concerning how the aging effects will be managed. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the aging effects will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.2.2.3.1 Engineered Safety Features – Containment Hydrogen Recombiner System – Summary of Aging Management Evaluation – LRA Table 3.2.2-1

The staff reviewed LRA Table 3.2.2-1, which summarizes the results of AMR evaluations for the containment hydrogen recombiner system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.2.2.1.

3.2.2.3.2 Engineered Safety Features – Core Spray System – Summary of Aging Management Evaluation – LRA Table 3.2.2-2

The staff reviewed LRA Table 3.2.2-2, which summarizes the results of AMR evaluations for the core spray system component groups.

In LRA Table 3.2.2-2, the applicant stated that stainless steel bolting components exposed to treated water are being managed for loss of material due to pitting and crevice corrosion and loss of preload due to thermal effects, gasket creep, and self-loosening by the Bolting Integrity Program. The AMR line items cite generic note G, which indicate that the environment is not addressed in the GALL Report for this component and material.

The staff reviewed the applicant's Bolting Integrity Program and its evaluation is documented in SER Section 3.0.3.2.4. The staff finds the applicant's Bolting Integrity Program acceptable to manage loss of material and loss of preload for these components because it performs visual inspections of bolting for pressure retaining components for visible leakage and fastener degradation to detect loss of material and loss of preload; and it has incorporated industry guidance on good bolting practices into its installation procedures.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.3 Engineered Safety Features – Filtration, Recirculation, and Ventilation System– Summary of Aging Management Evaluation – LRA Table 3.2.2-3

In LRA Table 3.2.2-3, the applicant stated that polymer ducting and components exposed to air – indoor (external) or air/gas – wetted (internal) have no AERM and that for this component, material, and environment combination, no AMP is needed. The AMR line items cite generic note F, indicating that the material is not in the GALL Report for this component.

The staff reviewed all material entries in the GALL Report and confirmed that polymer material is not included in the GALL Report. For these AMR results, the applicant also cited plant-specific note 3, stating that:

> The polymer (plexiglass) material located indoors and subject to an indoor air or air-gas (wetted) environment is not subject to significant aging effects. Polymer materials do not experience aging effects unless exposed to temperatures, radiation, or chemicals capable of attacking the specific polymer chemical composition[.] Polymer materials are selected for compatibility with the environment during the design, and if properly selected[,] will not experience significant degradation. Polymer (plexiglass) material in this non-aggressive air environment is not expected to experience significant aging effects. This is consistent with plant operating experience.

Based on its review of technical literature (e.g., Roff, W.J., *Fibres, Plastics, and Rubbers: A Handbook of Common Polymers*, Academic Press Inc., New York, 1956), and current industry research and operating experience related to plexiglass and related polymers, the staff has determined that, in the absence of specific environmental stressors such as ultraviolet light, high radiation, or ozone concentrations, components made of these materials do not exhibit aging effects of concern during the period of extended operation. The staff has determined that for plexiglass and related polymer components in a plant indoor air or air/gas – wetted environment, there are no aging effects that cause degradation of the components during the period of extended operation. On the basis that the subject components have no aging effects that cause degradation during the period of extended operation, the staff finds the applicant's

AMR results for these components, indicating that no AERM and no AMP is needed, to be acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.4 Engineered Safety Features – High Pressure Coolant Injection System – Summary of Aging Management Evaluation – LRA Table 3.2.2-4

The staff reviewed LRA Table 3.2.2-4, which summarizes the results of AMR evaluations for the HPCI system component groups.

In LRA Table 3.2.2-4, the applicant stated that stainless steel bolting components exposed to treated water are being managed for loss of material due to pitting and crevice corrosion and loss of preload due to thermal effects, gasket creep, and self-loosening by the Bolting Integrity Program. The AMR line items cite generic note G, which indicate that the environment is not addressed in the GALL Report for this component and material.

The staff reviewed the applicant's Bolting Integrity Program and its evaluation is documented in SER Section 3.0.3.2.4. The staff finds the applicant's Bolting Integrity Program acceptable to manage loss of material and loss of preload for these components because it performs visual inspections of bolting for pressure retaining components for visible leakage and fastener degradation to detect loss of material and loss of preload; and it has incorporated industry guidance on good bolting practices into its installation procedures.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.5 Engineered Safety Features – Hydrogen and Oxygen Analyzer System – Summary of Aging Management Evaluation – LRA Table 3.2.2-5

The staff reviewed LRA Table 3.2.2-5, which summarizes the results of AMR evaluations for the hydrogen and oxygen analyzer system component groups.

In LRA Table 3.2.2-5, the applicant stated that air cooled stainless steel heat exchanger components exposed externally to indoor air and internally to wetted air or gas are being managed for reduction of heat transfer and fouling by the Periodic Inspection Program. The AMR line item for exposure to indoor air cites generic note G, which indicates that the environment is not addressed in the GALL Report for this component and material. The AMR line item for exposure to wetted air or gas cites generic note H, which indicates that the aging effect is not addressed in the GALL Report for this component, material, and environment combination.

The staff reviewed the applicant's Periodic Inspection Program and its evaluation is documented in SER Section 3.0.3.3.2. The staff finds the applicant's Periodic Inspection Program acceptable to manage reduction of heat transfer and fouling for these components because it performs visual inspections of heat transfer surfaces which are capable of detecting reduction of heat transfer and fouling.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.6 Engineered Safety Features – Reactor Core Isolation Cooling System– Summary of Aging Management Evaluation – LRA Table 3.2.2-6

In LRA Table 3.2.2-6, the applicant stated that stainless steel bolting components exposed to treated water are being managed for loss of material due to pitting and crevice corrosion and loss of preload due to thermal effects, gasket creep, and self-loosening by the Bolting Integrity Program. The AMR line items cite generic note G, which indicates that the environment is not addressed in the GALL Report for this component and material.

The staff reviewed the applicant's Bolting Integrity Program and its evaluation is documented in SER Section 3.0.3.2.4. The staff finds the applicant's Bolting Integrity Program acceptable to manage loss of material and loss of preload for these components because it performs visual inspections of bolting for pressure retaining components for visible leakage and fastener degradation to detect loss of material and loss of preload; and it has incorporated industry guidance on good bolting practices into its installation procedures.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.7 Engineered Safety Features – Residual Heat Removal System – Summary of Aging Management Evaluation – LRA Table 3.2.2-7

In LRA Table 3.2.2-7, the applicant stated that stainless steel bolting components exposed to treated water are being managed for loss of material due to pitting and crevice corrosion and loss of preload due to thermal effects, gasket creep, and self-loosening by the Bolting Integrity Program. The AMR line items cite generic note G, which indicates that the environment is not addressed in the GALL Report for this component and material.

The staff reviewed the applicant's Bolting Integrity Program and its evaluation is documented in SER Section 3.0.3.2.4. The staff finds the applicant's Bolting Integrity Program acceptable to manage loss of material and loss of preload for these components because it performs visual inspections of bolting for pressure retaining components for visible leakage and fastener degradation to detect loss of material and loss of preload; and it has incorporated industry guidance on good bolting practices into its installation procedures.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.8 Engineered Safety Features – Vacuum Relief Valve System – Summary of Aging Management Evaluation – LRA Table 3.2.2-8

The staff reviewed LRA Table 3.2.2-8, which summarizes the results of AMR evaluations for the vacuum relief valve system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.2.2.1.

3.2.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the ESF system components within the scope of license renewal and 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, as required by 10 CFR 54.21(a)(3).

3.3 Aging Management of Auxiliary Systems

This section of the SER documents the staff's review of the applicant's AMR results for the auxiliary systems components and component groups of the:

- chilled water system
- closed-cycle cooling water system
- compressed air system
- containment inerting and purging system
- control area chilled water system
- control rod drive system
- control room and control area HVAC systems
- cranes and hoists
- equipment and floor drainage system
- fire protection system
- fire pump house ventilation system
- fresh water supply system
- fuel handling and storage system
- fuel pool cooling and cleanup system
- hardened torus vent system
- hydrogen water chemistry system
- leak detection and radiation monitoring system
- makeup demineralizer system
- primary containment instrument gas system
- primary containment leakage rate testing system
- process and post-accident sampling system
- radwaste system
- reactor building ventilation system
- reactor water cleanup system
- remote shutdown panel room HVAC system
- service water intake ventilation system
- service water system
- standby diesel generator area ventilation systems
- standby diesel generators and auxiliary systems
- standby liquid control system
- torus water cleanup system
- traversing incore probe system

3.3.1 Summary of Technical Information in the Application

LRA Section 3.3 provides AMR results for the auxiliary systems components and component groups. LRA Table 3.3.1, "Summary of Aging Management Evaluations for the Auxiliary Systems," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the auxiliary systems components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.3.2 Staff Evaluation

The staff reviewed LRA Section 3.3 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for auxiliary system components within the scope of license renewal and 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, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit of AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to verify the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.3.2.1 and 3.3.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.3.2.3.

For components which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.3-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.3 and addressed in the GALL Report.

Table 3.3-1 Staff Evaluation for Auxiliary System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel cranes - structural girders exposed to air – indoor uncontrolled (external) (3.3.1-1)	Cumulative fatigue damage	TLAA to be evaluated for structural girders of cranes. See SRP-LR Section 4.7 for generic guidance for meeting the requirements of 10 CFR 54.21(c)(1).	Yes	TLAA	Fatigue is a TLAA (See SER Section 3.3.2.2.1)
Steel and stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air – indoor uncontrolled, treated borated water, or treated water (3.3.1-2)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (See SER Section 3.3.2.2.1)
Stainless steel heat exchanger tubes exposed to treated water (3.3.1-3)	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.2)
Stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution > 60 °C (140 °F) (3.3.1-4)	Cracking due to SCC	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.2.3)
Stainless steel and stainless clad steel heat exchanger components exposed to treated water > 60 °C (140 °F) (3.3.1-5)	Cracking due to SCC	A plant-specific AMP is to be evaluated.	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (3.3.1-6)	Cracking due to SCC	A plant-specific AMP is to be evaluated.	Yes	Periodic Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.3)
Stainless steel non-regenerative heat exchanger components exposed to treated borated water > 60 °C (140 °F) (3.3.1-7)	Cracking due to SCC and cyclic loading	Water Chemistry and a plant-specific verification program. An acceptable verification program is to include temperature and radioactivity monitoring of the shell side water, and eddy current testing of tubes.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.3.2.2.4)
Stainless steel regenerative heat exchanger components exposed to treated borated water > 60 °C (140 °F) (3.3.1-8)	Cracking due to SCC and cyclic loading	Water Chemistry and a plant-specific verification program. The AMP is to be augmented by verifying the absence of cracking due to SCC and cyclic loading. A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.3.2.2.4)
Stainless steel high-pressure pump casing in PWR chemical and volume control system (3.3.1-9)	Cracking due to SCC and cyclic loading	Water Chemistry and a plant-specific verification program. The AMP is to be augmented by verifying the absence of cracking due to SCC and cyclic loading. A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.3.2.2.4)
High-strength steel closure bolting exposed to air with steam or water leakage (3.3.1-10)	Cracking due to SCC and cyclic loading	Bolting Integrity. The AMP is to be augmented by appropriate inspection to detect cracking if the bolts are not otherwise replaced during maintenance.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.2.4)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Elastomer seals and components exposed to air – indoor uncontrolled (internal/external) (3.3.1-11)	Hardening and loss of strength due to elastomer degradation	A plant-specific AMP is to be evaluated.	Yes	Periodic Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.5)
Elastomer lining exposed to treated water or treated borated water (3.3.1-12)	Hardening and loss of strength due to elastomer degradation	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Consistent with GALL Report (See SER Section 3.3.2.2.5)
Boral®, boron steel spent fuel storage racks neutron-absorbing sheets exposed to treated water or treated borated water (3.3.1-13)	Reduction of neutron-absorbing capacity and loss of material due to general corrosion	A plant-specific AMP is to be evaluated.	Yes	Boral Monitoring Program and Water Chemistry	Consistent with GALL Report (See SER Section 3.3.2.2.6)
Steel piping, piping component, and piping elements exposed to lubricating oil (3.3.1-14)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Lubricating Oil Analysis and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.7)
Steel reactor coolant pump oil collection system piping, tubing, and valve bodies exposed to lubricating oil (3.3.1-15)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.2.7)
Steel reactor coolant pump oil collection system tank exposed to lubricating oil (3.3.1-16)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection to evaluate the thickness of the lower portion of the tank	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.2.7)
Steel piping, piping components, and piping elements exposed to treated water (3.3.1-17)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.7)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (3.3.1-18)	Loss of material/general (steel only), pitting, and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Periodic Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.7)
Steel (with or without coating or wrapping) piping, piping components, and piping elements exposed to soil (3.3.1-19)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	No Yes	Buried Piping Inspection Aboveground Steel Tanks; RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"; and Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.3.2.2.8)
Steel piping, piping components, piping elements, and tanks exposed to fuel oil (3.3.1-20)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling	Fuel Oil Chemistry and One-Time Inspection	Yes	Fuel Oil Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.9)
Steel heat exchanger components exposed to lubricating oil (3.3.1-21)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling	Lubricating Oil Analysis and One-Time Inspection	Yes	Lubricating Oil Analysis and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.9)
Steel with elastomer lining or stainless steel cladding piping, piping components, and piping elements exposed to treated water and treated borated water (3.3.1-22)	Loss of material due to pitting and crevice corrosion (only for steel after lining/cladding degradation)	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.2.10)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water (3.3.1-23)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.10)
Stainless steel and aluminum piping, piping components, and piping elements exposed to treated water (3.3.1-24)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.10)
Copper alloy HVAC piping, piping components, piping elements exposed to condensation (external) (3.3.1-25)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Periodic Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.10)
Copper alloy piping, piping components, and piping elements exposed to lubricating oil (3.3.1-26)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Lubricating Oil Analysis and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.10)
Stainless steel HVAC ducting and aluminum HVAC piping, piping components, and piping elements exposed to condensation (3.3.1-27)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Periodic Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.10)
Copper alloy fire protection piping, piping components, and piping elements exposed to condensation (internal) (3.3.1-28)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Fire Water System	Consistent with GALL Report (See SER Section 3.3.2.2.10)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to soil (3.3.1-29)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.2.10)
Stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution (3.3.1-30)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.10)
Copper alloy piping, piping components, and piping elements exposed to treated water (3.3.1-31)	Loss of material due to pitting, crevice, and galvanic corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.11)
Stainless steel, aluminum and copper alloy piping, piping components, and piping elements exposed to fuel oil (3.3.1-32)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion	Fuel Oil Chemistry and One-Time Inspection	Yes	Fuel Oil Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.12)
Stainless steel piping, piping components, and piping elements exposed to lubricating oil (3.3.1-33)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Lubricating Oil Analysis and One-Time Inspection	Consistent with GALL Report (See SER Section 3.3.2.2.12)
Elastomer seals and components exposed to air – indoor uncontrolled (internal or external) (3.3.1-34)	Loss of material due to wear	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.2.13)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel with stainless steel cladding pump casing exposed to treated borated water (3.3.1-35)	Loss of material due to cladding breach	A plant-specific AMP is to be evaluated. Reference NRC IN 94-63, “Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks”	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.3.2.2.14)
Boraflex spent fuel storage racks neutron-absorbing sheets exposed to treated water (3.3.1-36)	Reduction of neutron-absorbing capacity due to boraflex degradation	Boraflex Monitoring	No	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60 °C (140 °F) (3.3.1-37)	Cracking due to SCC and IGSCC	BWR Reactor Water Cleanup System	No	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60 °C (140 °F) (3.3.1-38)	Cracking due to SCC	BWR Stress Corrosion Cracking and Water Chemistry	No	BWR Stress Corrosion Cracking and Water Chemistry	Consistent with GALL Report
Stainless steel BWR spent fuel storage racks exposed to treated water > 60 °C (140 °F) (3.3.1-39)	Cracking due to SCC	Water Chemistry	No	Not applicable	Not applicable to HCGS
Steel tanks in diesel fuel oil system exposed to air – outdoor (external) (3.3.1-40)	Loss of material due to general, pitting, and crevice corrosion	Aboveground Steel Tanks	No	Aboveground Steel Tanks	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High-strength steel closure bolting exposed to air with steam or water leakage (3.3.1-41)	Cracking due to cyclic loading and SCC	Bolting Integrity	No	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.1.1)
Steel closure bolting exposed to air with steam or water leakage (3.3.1-42)	Loss of material due to general corrosion	Bolting Integrity	No	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.1.1)
Steel bolting and closure bolting exposed to air – indoor uncontrolled (external) or air – outdoor (external) (3.3.1-43)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	No	Bolting Integrity Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with GALL Report (See SER Section 3.3.2.1.2)
Steel compressed air system closure bolting exposed to condensation (3.3.1-44)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	No	Not applicable Bolting Integrity	Not applicable to HCGS (See SER Section 3.3.2.1.1)
Steel closure bolting exposed to air – indoor uncontrolled (external) (3.3.1-45)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity ASME Section XI, Subsection IWF Structures Monitoring Program Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems RG 1.127,"Inspection of Water-Control Structures Associated with Nuclear Power Plants""	Consistent with GALL Report (See SER Sections 3.3.2.1.3 and 3.5.2.1.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and stainless clad steel piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water > 60 °C (140 °F) (3.3.1-46)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with GALL Report
Steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to closed-cycle cooling water (3.3.1-47)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with GALL Report
Steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to closed-cycle cooling water (3.3.1-48)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with GALL Report
Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water (3.3.1-49)	Loss of material due to microbiologically-influenced corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.3.1-50)	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water (3.3.1-51)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with GALL Report
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to closed-cycle cooling water (3.3.1-52)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with GALL Report
Steel compressed air system piping, piping components, and piping elements exposed to condensation (internal) (3.3.1-53)	Loss of material due to general and pitting corrosion	Compressed Air Monitoring	No	Compressed Air Monitoring	Consistent with GALL Report
Stainless steel compressed air system piping, piping components, and piping elements exposed to internal condensation (3.3.1-54)	Loss of material due to pitting and crevice corrosion	Compressed Air Monitoring	No	Compressed Air Monitoring Periodic Inspection and Fire Protection	Consistent with GALL Report (See SER Section 3.3.2.1.5)
Steel ducting closure bolting exposed to air – indoor uncontrolled (external) (3.3.1-55)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with GALL Report
Steel HVAC ducting and components external surfaces exposed to air – indoor uncontrolled (external) (3.3.1-56)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping and components external surfaces exposed to air – indoor uncontrolled (external) (3.3.1-57)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring Fire Protection Fire Water System	Consistent with GALL Report (See SER Section 3.3.2.1.4)
Steel external surfaces exposed to air – indoor uncontrolled (external), air – outdoor (external), and condensation (external) (3.3.1-58)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring Fire Protection Fire Water System Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.3.2.1.4)
Steel heat exchanger components exposed to air – indoor uncontrolled (external) or air – outdoor (external) (3.3.1-59)	Loss of material due to general, pitting, and crevice corrosion	External Surfaces Monitoring	No	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.1.1)
Steel piping, piping components, and piping elements exposed to air – outdoor (external) (3.3.1-60)	Loss of material due to general, pitting, and crevice corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring Fire Protection Fire Water System Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with GALL Report (See SER Section 3.3.2.1.2)
Elastomer fire barrier penetration seals exposed to air – outdoor or air – indoor uncontrolled (3.3.1-61)	Increased hardness, shrinkage, and loss of strength due to weathering	Fire Protection	No	Fire Protection Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.3.2.1.10)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Aluminum piping, piping components, and piping elements exposed to raw water (3.3.1-62)	Loss of material due to pitting and crevice corrosion	Fire Protection	No	Not applicable	Not applicable to HCGS
Steel fire rated doors exposed to air – outdoor or air – indoor uncontrolled (3.3.1-63)	Loss of material due to wear	Fire Protection	No	Fire Protection	Consistent with GALL Report
Steel piping, piping components, and piping elements exposed to fuel oil (3.3.1-64)	Loss of material due to general, pitting, and crevice corrosion	Fire Protection and Fuel Oil Chemistry	No	Not applicable	Not applicable to HCGS
Reinforced concrete structural fire barriers - walls, ceilings, and floors exposed to air – indoor uncontrolled (3.3.1-65)	Concrete cracking and spalling due to aggressive chemical attack, and reaction with aggregates	Fire Protection and Structures Monitoring Program	No	Not applicable	Not applicable to HCGS (See SER Section 3.3.2.1.1)
Reinforced concrete structural fire barriers - walls, ceilings, and floors exposed to air – outdoor (3.3.1-66)	Concrete cracking and spalling due to freeze thaw, aggressive chemical attack, and reaction with aggregates	Fire Protection and Structures Monitoring Program	No	Fire Protection and Structures Monitoring Program	Consistent with GALL Report
Reinforced concrete structural fire barriers - walls, ceilings, and floors exposed to air – outdoor or air – indoor uncontrolled (3.3.1-67)	Loss of material due to corrosion of embedded steel	Fire Protection and Structures Monitoring Program	No	Fire Protection and Structures Monitoring Program	Consistent with GALL Report
Steel piping, piping components, and piping elements exposed to raw water (3.3.1-68)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling	Fire Water System	No	Fire Water System Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (See SER Section 3.3.2.1.6)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-69)	Loss of material due to pitting and crevice corrosion, and fouling	Fire Water System	No	Not applicable	Not applicable to HCGS
Copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-70)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling	Fire Water System	No	Fire Water System	Consistent with GALL Report
Steel piping, piping components, and piping elements exposed to moist air or condensation (internal) (3.3.1-71)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (See SER Section 3.3.2.1.2)
Steel HVAC ducting and components internal surfaces exposed to condensation (internal) (3.3.1-72)	Loss of material due to general, pitting, crevice, and (for drip pans and drain lines) microbiologically-influenced corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Fire Protection	Consistent with GALL Report (See SER Section 3.3.2.1.9)
Steel crane structural girders in load handling system exposed to air – indoor uncontrolled (external) (3.3.1-73)	Loss of material due to general corrosion	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	No	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with GALL Report
Steel cranes - rails exposed to air – indoor uncontrolled (external) (3.3.1-74)	Loss of material due to wear	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	No	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Elastomer seals and components exposed to raw water (3.3.1-75)	Hardening and loss of strength due to elastomer degradation; loss of material due to erosion	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System	Consistent with GALL Report
Steel piping, piping components, and piping elements (without lining/ coating or with degraded lining/coating) exposed to raw water (3.3.1-76)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion, fouling, and lining/coating degradation	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System	Consistent with GALL Report
Steel heat exchanger components exposed to raw water (3.3.1-77)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Fire Water System Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (See SER Section 3.3.2.1.7)
Stainless steel, nickel alloy, and copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-78)	Loss of material due to pitting and crevice corrosion	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-79)	Loss of material due to pitting and crevice corrosion, and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-80)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-81)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System Periodic Inspection	Consistent with GALL Report (See SER Section 3.3.2.1.8)
Copper alloy heat exchanger components exposed to raw water (3.3.1-82)	Loss of material due to pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Not applicable Periodic Inspection	Not applicable to HCGS
Stainless steel and copper alloy heat exchanger tubes exposed to raw water (3.3.1-83)	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	No	Not applicable Periodic Inspection	Not applicable to HCGS
Copper alloy > 15% Zn piping, piping components, piping elements, and heat exchanger components exposed to raw water, treated water, or closed-cycle cooling water (3.3.1-84)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Selective Leaching of Materials	Consistent with GALL Report
Gray cast iron piping, piping components, and piping elements exposed to soil, raw water, treated water, or closed-cycle cooling water (3.3.1-85)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Selective Leaching of Materials	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Structural steel (new fuel storage rack assembly) exposed to air – indoor uncontrolled (external) (3.3.1-86)	Loss of material due to general, pitting, and crevice corrosion	Structures Monitoring Program	No	Not applicable	Not applicable to HCGS
Boraflex spent fuel storage racks neutron-absorbing sheets exposed to treated borated water (3.3.1-87)	Reduction of neutron-absorbing capacity due to boraflex degradation	Boraflex Monitoring	No	Not applicable	Not applicable to BWRs
Aluminum and copper alloy > 15% Zn piping, piping components, and piping elements exposed to air with borated water leakage (3.3.1-88)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Not applicable	Not applicable to BWRs
Steel bolting and external surfaces exposed to air with borated water leakage (3.3.1-89)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Not applicable	Not applicable to BWRs
Stainless steel and steel with stainless steel cladding piping, piping components, piping elements, tanks, and fuel storage racks exposed to treated borated water > 60 °C (140 °F) (3.3.1-90)	Cracking due to SCC	Water Chemistry	No	Not applicable	Not applicable to BWRs

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and steel with stainless steel cladding piping, piping components, and piping elements exposed to treated borated water (3.3.1-91)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Not applicable	Not applicable to BWRs
Galvanized steel piping, piping components, and piping elements exposed to air – indoor uncontrolled (3.3.1-92)	None	None	No	None	Consistent with GALL Report (See SER Section 3.3.2.1.2)
Glass piping elements exposed to air, air – indoor uncontrolled (external), fuel oil, lubricating oil, raw water, treated water, and treated borated water (3.3.1-93)	None	None	No	None	Consistent with GALL Report
Stainless steel and nickel-alloy piping, piping components, and piping elements exposed to air – indoor uncontrolled (external) (3.3.1-94)	None	None	No	None	Consistent with GALL Report (See SER Section 3.3.2.1.5)
Steel and aluminum piping, piping components, and piping elements exposed to air – indoor controlled (external) (3.3.1-95)	None	None	No	Not applicable	Not applicable to HCGS
Steel and stainless steel piping, piping components, and piping elements in concrete (3.3.1-96)	None	None	No	None	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas (3.3.1-97)	None	None	No	None	Consistent with GALL Report
Steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to dried air (3.3.1-98)	None	None	No	Compressed Air Monitoring	Consistent with GALL Report (See SER Section 3.3.2.1.11)
Stainless steel and copper alloy < 15% Zn piping, piping components, and piping elements exposed to air with borated water leakage (3.3.1-99)	None	None	No	Not applicable	Not applicable to BWRs

The staff's review of the auxiliary systems component groups followed several approaches. One approach, documented in SER Section 3.3.2.1, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.3.2.2, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.3.2.3, discusses the staff's review of AMR results for components the applicant indicated are not consistent with or not addressed in the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the auxiliary systems components is documented in SER Section 3.0.3.

3.3.2.1 AMR Results That Are Consistent with the GALL Report

LRA Section 3.3.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the auxiliary systems components:

- ASME Section XI Inservice Inspection, IWB, IWC, and IWD
- Aboveground Steel Tanks
- Bolting Integrity

- Boral Monitoring Program
- Buried Non-Steel Piping Inspection
- Buried Piping Inspection
- BWR Stress Corrosion Cracking
- Closed-Cycle Cooling Water System
- Compressed Air Monitoring
- External Surfaces Monitoring
- Fire Protection
- Fire Water System
- Flow-Accelerated Corrosion
- Fuel Oil Chemistry Program
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Lubricating Oil Analysis
- One-Time Inspection
- Open-Cycle Cooling Water System
- Periodic Inspection
- Selective Leaching of Materials
- Small-Bore Class 1 Piping Inspection
- Structures Monitoring Program
- TLAA
- Water Chemistry

LRA Tables 3.3.2-1 through 3.3.2-32 summarize AMRs for the auxiliary systems components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant had claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and confirmed that it had reviewed and accepted the identified exceptions to the GALL Report AMPs. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component applied to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and confirmed whether the AMR line item of the different component was applicable to the component under review. The staff confirmed whether it had reviewed and accepted the exceptions to the GALL Report AMPs. It also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report and determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff did not repeat its review of the matters described in the GALL Report; however, it did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

The staff reviewed the LRA to confirm that the applicant: (1) provided a brief description of the system, components, materials, and environments; (2) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (3) identified those aging effects for the auxiliary systems components that are subject to an AMR.

On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.3.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

The staff notes that in LRA Tables 3.3.2-2, 3.3.2-5, 3.3.2-9, 3.3.2-10, 3.3.2-16, 3.3.2-22, 3.3.2-24, 3.3.2-27, 3.3.2-29, and 3.3.2-30, there are multiple tank line items exposed to material and environment combinations including carbon steel exposed to closed-cycle cooling water, treated water, raw water, and fuel oil and stainless steel exposed to treated water, raw water, and sodium pentaborate. The staff also notes that the LRA does not have a line item for the tank material exposed to an air or wetted gas internal environment as would occur when the tank is partially full. The staff further notes that in each instance, LRA line items manage the aging of the tank internal surfaces using a program that requires an internal inspection of the tank when appropriate (for example, the Closed-Cycle Cooling Water Program requires a one-time inspection of stagnant flow areas and internals of selected chemical mixing tanks). These programs include the Closed-Cycle Cooling Water System, Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components, Periodic Inspections, One-Time Inspections, and the Fire Water System Programs. The staff finally notes that in appropriate cases, the LRA line items uses a chemistry control program inclusive of the Water Chemistry, Fuel Oil, and Closed-Cycle Cooling Water System Programs. The staff finds the existing line items acceptable because the chemistry program will minimize contaminant concentrations and thus mitigate loss of material due to various corrosion mechanisms for tank internal surfaces at the fluid to air transition zone, and the inspection related programs will provide reasonable assurance that an aging effect is not affecting the components intended function.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In RAI B.2.1.12-01, the staff asked the applicant to explain how the applicant ensures that other AMPs credited for aging management of component support and structural bolting include all the recommendations for aging management of bolting in GALL AMP XI.M18. LRA Tables 3.3.2-8 and 3.3.2-13 were revised as a result of the response to RAI B.2.1.12-01, dated June 14, 2010. The revision added AMR items in these tables to reference the applicant's Bolting Integrity Program to manage the aging for bolting AMR items. Existing bolting AMR items which reference other AMPs are used in conjunction with the added bolting AMR items to properly manage aging for bolting components. The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.4. The staff notes that the Bolting Integrity Program is supplemented by other AMPs, including but not limited to the Structures Monitoring, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems, External Surfaces Monitoring, and Buried Piping Inspection Programs. These other AMPs supplement the Bolting Integrity Program by implementing the requirements of the Bolting Integrity Program for pressure retaining bolted joints, component support bolting, and structural bolting within the scope of license renewal. The applicant's action revised the LRA to add bolting component items in the tables mentioned above that are consistent with the GALL Report and have designated them as such with generic note B.

3.3.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.3.1, item 3.3.1-36 addresses reduction of neutron-absorbing capacity due to Boraflex degradation in Boraflex spent fuel storage racks neutron-absorbing sheets exposed to treated water. The applicant stated that this line item is not applicable because there are no Boraflex spent fuel storage racks neutron-absorbing sheets exposed to treated water for the auxiliary systems. The staff reviewed LRA Sections 2.3.3 and 3.3 and confirmed that the applicant's LRA does not have any AMR results that include Boraflex spent fuel storage racks neutron-absorbing sheets exposed to treated water. The staff also reviewed the applicant's UFSAR and confirmed that no in-scope Boraflex spent fuel storage racks neutron-absorbing sheets exposed to treated water are present in the spent fuel storage system and, therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.3.1, item 3.3.1-37 addresses cracking due to SCC and IGSCC in stainless steel piping, piping components, and piping elements exposed to treated water greater than 60 °C (140 °F). The applicant stated that this line item is not applicable because it has met the screening criteria for not implementing GALL AMP XI.M25, "BWR Reactor Water Cleanup System." The staff reviewed the applicant's claim of meeting the screening criteria and confirmed that it matched that of GALL AMP XI.M25 and, therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.3.1, item 3.3.1-41 addresses high-strength steel closure bolting exposed to air with steam or water leakage in the auxiliary systems. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to manage cracking due to cyclic loading or SCC for this component group. The applicant stated that this item is not applicable because there is no high-strength closure bolting in the auxiliary systems. The staff reviewed LRA Sections 2.3.3 and 3.3 and confirmed that the applicant's LRA does not have any AMR results for the auxiliary systems that include high-strength steel closure bolting exposed to air with steam or water leakage. The staff reviewed the applicant's UFSAR and confirmed that no in-scope high-strength steel closure bolting exposed to air with steam or water leakage is present in the auxiliary systems and, therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.3.1, item 3.3.1-42 addresses steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to manage loss of material due to general corrosion for this component group. The applicant stated that this item is not applicable because the AMR methodology for steel closure bolting predicts pitting and crevice corrosion in addition to general corrosion, and as a result, item 3.3.1-43 is credited for this component instead. The staff evaluated the applicant's claim and found it acceptable because the applicant: (1) identified the loss of material due to general, pitting, and crevice corrosion aging effect which is a more conservative approach than the loss of material due to general corrosion aging effect for this component group; and (2) has credited an alternate Table 1, item 3.3.1-43 to manage this component group.

LRA Table 3.3.1, item 3.3.1-44 addresses steel compressed air system closure bolting exposed to condensation. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to manage loss of material due to general, pitting, and crevice corrosion for this component group. The applicant stated that this item is not applicable because steel closure bolting is evaluated by item 3.3.1-43, and also that the Bolting Integrity Program is used to manage loss of material due to general, pitting, and crevice corrosion of the steel bolting. The staff evaluated the applicant's claim and found it acceptable because the applicant has credited an alternate Table 1, item 3.3.1-43 to manage this component group which applies the same AMP as that recommended for item 3.3.1-44 and is also capable of managing the aging effect for this component group.

LRA Table 3.3.1, item 3.3.1-59 addresses loss of material due to general, pitting, and crevice corrosion in steel heat exchanger components exposed externally to uncontrolled indoor and outdoor air. The GALL Report recommends GALL AMP XI.M36, “External Surfaces Monitoring.” The applicant stated that this line item is not applicable because AMR methodology assumes steel heat exchanger components are located indoors and exposed to uncontrolled indoor air, and as a result, item 3.3.1-58 is credited to manage aging for this component instead. LRA Table 3.3.1-58 addresses steel external surfaces exposed to indoor uncontrolled or outdoor air. The GALL Report also recommends GALL AMP XI.M36 to manage aging effects for this component group. The staff evaluated the applicant’s claim and found it acceptable because although the applicant credited an alternate line item (3.3.1-58) to manage this component group, the components are being managed by the same AMP as recommended for item 3.3.1-59, which performs visual inspections capable of detecting loss of material.

LRA Table 3.3.1, item 3.3.1-65 addresses reinforced concrete structural fire barriers (i.e., walls, ceilings, and floors) exposed to indoor uncontrolled air being managed for cracking and spalling due to aggressive chemical attack and reaction with aggregates. The LRA states that this line item is not applicable and that these aging effects and mechanisms for concrete structural fire barriers are addressed with the applicable building structure in LRA Section 3.5. The GALL Report recommends the use of GALL AMP XI.M26, “Fire Protection,” and GALL AMP XI.S6, “Structures Monitoring,” to manage these aging effects. The staff notes that the Structures Monitoring Program performs inspections such that structures are inspected at least once in 10 years, while the Fire Protection Program performs inspections on an 18 month frequency for fire barriers outside containment. The staff reviewed LRA Section 3.5 and could not determine where this material, environment, and aging effect were addressed for fire barriers because there were no entries for these components being managed by the Fire Protection Program.

By letter dated June 22, 2010, the staff issued RAI 3.3.1.65-1 requesting that the applicant identify how reinforced concrete structural fire barriers (e.g., walls, ceilings, and floors) exposed to indoor uncontrolled air are being adequately managed for the aging effects of cracking and spalling due to aggressive chemical attack and reaction with aggregates.

In its response dated July 19, 2010, the applicant stated that above-grade and interior concrete is not exposed to an aggressive chemical attack, and reaction with aggregates is not an applicable aging effect because it uses only low alkali cement that has been tested in accordance with ASTM C289 and C295 to resist reaction with aggregates. The applicant also stated that cracking, loss of bond, and loss of material are applicable aging effects for concrete and are being managed under item 3.5.1-23; and that the AMR result line to manage these aging effects using the Fire Protection Program was inadvertently omitted from Table 3.3.2-10. As a result, the applicant revised Table 3.3.2-10 to add an AMR result line for reinforced concrete fire barriers (e.g., walls, ceilings, and floors) exposed to indoor uncontrolled air which are being managed for cracking, loss of bond, and loss of material by the Fire Protection Program under item 3.5.10-23, which cites generic note E. The applicant further stated that even though the AMR result line was inadvertently omitted, the Fire Protection Program includes inspections of these fire barriers once every 18 months.

The staff finds the applicant’s response to RAI 3.3.1.65-1, its determination that item 3.3.1-65 is not applicable, and its proposal to manage aging for reinforced concrete fire barrier walls, ceilings, and floors using the Fire Protection and Structures Monitoring Programs acceptable because: (1) addition of an AMR result which manages aging using the Fire Protection Program ensures the affected components are inspected at least once every 18 months, which is an appropriate frequency for inspection of fire barriers; (2) the components that would have been managed using item 3.3.1-65 are being appropriately managed by item 3.5.1-23; (3) the applicant uses only low alkali cement which has been shown to not cause a reaction with aggregates; (4) the fire barriers are exposed to plant indoor air, which would not be expected to include aggressive chemicals; and (5) the programs both perform visual inspections which are effective at detecting cracking, loss of bond, and loss of material. The staff's concern described in RAI 3.3.1.65-1 is resolved.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-60 addresses steel piping, piping components, and piping elements exposed to air. In LRA Table 3.3.2-8, the applicant credits item 3.3.1-60 to manage aging for cranes and hoists. For this line item, the LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M36, "External Surfaces Monitoring," to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited.

For those line items associated with generic note E in Table 3.3.2-8, the staff noted that the applicant selected a Table 1 line item for piping, piping components, and piping elements, whereas for line items associated with generic note E in LRA Table 3.3.2-8, the component is listed as cranes/hoists. GALL AMP XI.M36 recommends using visual inspections to manage the aging of these line items. In its review of components associated with item 3.3.1-60 for which the applicant cited generic note E, the staff noted that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program proposes to manage the aging of carbon steel cranes and hoists through the use of visual inspections.

The staff's evaluation of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program is documented in SER Section 3.0.3.2.6. The staff noted that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program proposes to manage the aging effects of the structural steel components of plant cranes and hoists through the use of periodic visual inspections. In its review of components associated with item 3.3.1-60, the staff finds the applicant's proposal to manage aging using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program acceptable because the alternate AMP is able to properly manage the loss of material due to general, pitting, and crevice corrosion through the use of methods similar to those recommended by GALL AMP XI.M35, "External Surfaces Monitoring."

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-43 addresses steel bolting and closure bolting exposed to air – indoor uncontrolled (external) or air – outdoor (external) which are being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to ensure that these aging effects are adequately managed. The associated AMR line item cites generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited.

For those line items associated with generic note E, GALL AMP XI.M18 recommends using visual inspections to manage the aging of these line items. In its review of components associated with item 3.3.1-43 for which the applicant cited generic note E, the staff noted that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program proposes to manage the aging of carbon and low alloy steel bolting through the use of visual inspections.

The staff reviewed the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program and its evaluation is documented in SER Section 3.0.3.2.6. The staff noted that the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program uses procedures that have incorporated the guidance from ANSI B30.2, which includes proper installation and design criteria, and periodic visual inspections for loss of material. Also, the staff issued RAI B.2.1.12-01 requesting that the applicant explain why programs other than the Bolting Integrity Program were credited to manage aging effects for structural bolting.

In its response, which is evaluated in SER Section 3.0.3.2.4, the applicant added a number of AMR result lines, including some associated with LRA Table 3.3.1, item 3.3.1-43. The added AMR result lines credit the Bolting Integrity Program, in addition to the previously credited program to manage loss of material due to general, pitting, and crevice corrosion and cite generic note B, indicating that the results are consistent with the GALL Report for component, material, environment, and aging effect, but the AMP takes some exception(s) to the GALL Report. The staff finds the applicant's proposed combination of programs acceptable to manage aging for these components because: (1) the programs include visual inspections of bolting which are capable of detecting loss of preload, (2) the use of the Bolting Integrity Program is consistent with the recommendations in the GALL Report, and (3) supplementing the inspections performed by the Bolting Integrity Program with inspections performed by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program provides a more comprehensive approach to monitoring aging for these components.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-71 addresses steel piping, piping components, and piping elements exposed internally to moist air or condensation being managed for loss of material due to general pitting and crevice corrosion. The LRA credits the Fire Protection Program for steel and galvanized steel piping and fittings, and steel spray nozzles in the fire protection system. The GALL Report recommends GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to ensure that these aging effects are adequately managed. The AMR line items cite generic note E, which indicate that the line item is consistent with the GALL Report for the material, environment, and aging effect, but a different AMP is credited. The AMR line items also cite plant-specific note 1, indicating that the Fire Protection Program is substituted to manage the aging effects applicable to this component type, material, and environment combination. GALL AMP XI.M38 recommends performing inspections of the internal surfaces of piping and components to manage loss of material.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.7. The staff noted that the Fire Protection Program includes: (1) external visual inspections of fire barriers, seals, and doors; and (2) external visual inspections and functional testing of the diesel driven fire pump and halon and CO_2 fire suppression systems. In its review of components associated with item 3.3.1-71 for which the applicant cited generic note E, the staff noted that the applicant credited the Fire Protection Program to manage aging for steel and galvanized steel piping and fittings, and steel spray nozzles in LRA Table 3.3.2-10. However, the staff also noted that the Fire Protection Program does not include criteria for inspections of the internal surfaces of components to detect loss of material.

By letter dated June 22, 2010, the staff issued RAI 3.3.1-01 requesting that the applicant justify how the Fire Protection Program will adequately manage the aging effect of loss of material due to general, pitting, and crevice corrosion for these components in a wetted air or gas internal environment.

In its response dated July 19, 2010, the applicant stated that the galvanized steel piping and components in Table 3.3.2-10 are subject to the same internal environment as the external surfaces because the halon system uses open spray nozzles and the nozzles and piping are located in the control room, which is temperature and humidity controlled and is not subject to condensation or wetting that could cause corrosion. The applicant also stated that it has galvanized steel piping and steel spray nozzles in the foam fire suppression system that are subject to internal condensation or wetting. As a result, the applicant revised LRA Table 3.3.2-10 to: (1) add a line item for galvanized steel piping and fittings exposed internally to indoor air which references item 3.3.1-92 and cites generic note A; and (2) revise the line items associated with item 3.3.1-77 which cite note E and manage steel odorizers, piping and fittings, and galvanized steel piping, fittings, and spray nozzles exposed to wetted air or gas such that the revised items will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and cite generic note A.

The staff finds the applicant's response to RAI 3.3.1-01 and proposed programs to manage aging for these components acceptable because the applicant: (1) revised the environment for the stainless steel spray nozzles appropriately and aligned the components to an appropriate line item for the given material and environment combination; and (2) revised the LRA to include an inspection program that is applicable for managing aging for the internal surfaces of components and is consistent with the GALL Report recommendations for the given material, aging effect, and environment combination. The staff's concern described in RAI 3.3.1-01 is resolved.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-60 addresses steel piping, piping components, and piping elements exposed externally to outdoor air which are being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the Fire Water System Program in addition to the External Surfaces Monitoring Program for steel, gray cast iron, ductile cast iron, and galvanized steel piping and fittings, fire hydrants, hose manifolds, valve bodies, and thermowells in the fire protection system. The GALL Report recommends GALL AMP XI.M36, "External Surfaces Monitoring," to ensure that these aging effects are adequately managed. The AMR line items cite generic note E. The AMR line items also cite plant-specific note 12, indicating that the Fire Water System Program will be used in addition to the External Surfaces Monitoring Program.

GALL AMP XI.M36 recommends using periodic visual inspections of the external surfaces of steel components to manage these aging effects. In its review of components associated with item 3.3.1-60 for which the applicant cited generic note E, the staff noted that the applicant credited both the Fire Water System and External Surfaces Monitoring Program to manage aging for these items in LRA Table 3.3.2-10.

The staff reviewed the applicant's Fire Water System Program and its evaluation is documented in SER Section 3.0.3.2.8. The staff noted that the Fire Water System Program proposes to manage the aging effects of the steel components through the use of periodic visual inspections. The staff finds the proposed program acceptable to manage aging for these components because: (1) the proposed inspection method of visual inspection is the same and there are no substantive differences between the other program elements as compared to the GALL Report recommended AMP, and (2) the applicant is using the Fire Water System Program in addition to the External Surfaces Monitoring Program, which provides a more conservative approach to managing this aging effect.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-60 addresses steel piping, piping components, and piping elements exposed externally to outdoor air which are being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the Fire Protection Program in addition to the External Surfaces Monitoring Program to manage aging for steel piping and fittings, spray nozzles, and valve bodies in the fire protection system. The GALL Report recommends GALL AMP XI.M36, "External Surface Monitoring," to ensure that these aging effects are adequately managed. The AMR line items cite generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited. The AMR line items also cite plant-specific note 15, indicating that the Fire Protection Program will be used in addition to the External Surfaces Monitoring Program.

GALL AMP XI.M36 recommends using periodic visual inspections of the external surfaces of steel components to manage these aging effects. In its review of components associated with item 3.3.1-60 for which the applicant cited generic note E, the staff noted that the applicant credited both the Fire Protection and External Surfaces Monitoring Programs to manage aging for these items in LRA Table 3.3.2-10.

The staff reviewed the applicant's Fire Protection and External Surfaces Monitoring Programs and its evaluations are documented in SER Sections 3.0.3.2.7 and 3.0.3.1.13, respectively. The staff noted that the Fire Protection Program proposes to manage the aging effects of the steel components through the use of periodic visual inspections. The staff finds the proposed program acceptable to manage aging for these components because: (1) the proposed inspection method of visual inspection is the same as the inspection method in the GALL Report recommended AMP, and (2) the applicant is using the Fire Protection Program in addition to the External Surfaces Monitoring Program, which provides an effective approach to managing this aging effect.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-60 addresses steel piping, piping components, and piping elements exposed externally to outdoor air which are being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the Fire Protection Program to manage aging for steel doors in the fire protection system. The GALL Report recommends GALL AMP XI.M36, “External Surfaces Monitoring,” to ensure that these aging effects are adequately managed. The AMR line items cite generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited. The AMR line items also cite plant-specific note 1, indicating that the Fire Protection Program is substituted to manage the aging effects applicable to this component type, material, and environment combination.

GALL AMP XI.M36 recommends using periodic visual inspections of the external surfaces of steel components to manage these aging effects. In its review of components associated with item 3.3.1-60 for which the applicant cited generic note E, the staff noted that the applicant credited the Fire Protection Program to manage aging for steel doors in LRA Table 3.3.2-10.

The staff reviewed the applicant’s Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.7. The staff noted that the Fire Protection Program proposes to manage the aging effects of the steel doors through the use of periodic visual inspections. The staff finds the proposed program acceptable to manage aging for these components because the proposed inspection method of visual inspection is the same as the inspection method in the GALL Report recommended AMP.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.2.1, item 3.2.1-23 addresses steel bolting and closure bolting exposed externally to outdoor air or indoor uncontrolled air which are being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the External Surfaces Monitoring Program to manage loss of material for carbon and low alloy steel bolting in the filtration, recirculation, and ventilation system. The GALL Report recommends GALL AMP XI.M18, “Bolting Integrity,” to ensure these aging effects are adequately managed. The AMR line items cite generic note E. GALL AMP XI.M18 recommends performing periodic visual inspections to manage loss of material.

The staff reviewed the applicant’s External Surfaces Monitoring Program and its evaluation is documented in SER Section 3.0.3.1.13. The staff noted that the applicant’s External Surfaces Monitoring Program includes periodic visual inspections of bolting for signs of degradation due to loss of material and leakage at bolted joints. The staff finds the applicant's proposed program acceptable to manage aging for these components because it uses visual inspections to detect loss of material, which is consistent with the inspection methods in the recommended GALL Report AMP, and has incorporated the guidance recommended in GALL AMP XI.M18.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.3 Loss of Preload Due to Thermal Effects, Gasket Creep, and Self-Loosening

LRA Table 3.3.1, item 3.3.1-45 addresses carbon and low alloy steel bolting in the cranes and hoists system (LRA Table 3.3.2-8) and in the fuel handling and storage system (LRA Table 3.3.2-13); it also addresses carbon and low alloy steel or galvanized steel component support bolting or structural bolting in various buildings (LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-3, 3.5.2-4, 3.5.2-5, 3.5.3-7, 3.5.2-8, 3.5.2-11, and 3.5.2-12). For all AMR result lines associated with item 3.3.1-45, the environment is air – indoor and the aging effect being managed is loss of preload. The applicant stated that it associated these components with auxiliary system item 3.3.1-45 because of similarity of the component, material, environment, and aging effect combination. For item 3.3.1-45, the GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to manage loss of preload. The AMR line items in the LRA recommend managing loss of preload due to self-loosening with four alternative programs: (1) the Structures Monitoring Program; (2) the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program; (3) the ASME Section XI, Subsection IWF Program; and (4) the RG 1.127,"Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program." Where the applicant credits an alternative to the Bolting Integrity Program, the LRA cites generic note E, indicating that the result is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

During its review of AMR result lines associated with components for which the GALL Report recommends the Bolting Integrity Program, the staff noted that several other programs were identified to manage aging for bolting in the LRA. The staff issued RAI B.2.1.12-01 requesting that the applicant explain why programs other than the Bolting Integrity Program were credited to manage aging effects for structural and component support bolting.

In its response, which is evaluated in SER Section 3.0.3.2.4, the applicant added a number of AMR result lines, including some associated with LRA Table 3.3.1, item 3.3.1-45. The added AMR result lines credit the Bolting Integrity Program in addition to the previously credited programs to manage loss of material due to general, pitting, and crevice corrosion and cite generic note B, indicating that the results are consistent with the GALL Report for component, material, environment, and aging effect, but the AMP takes some exception(s) to the GALL Report. The staff finds the applicant's proposed combination of programs acceptable to manage aging for these components because: (1) the programs include visual inspections of bolting which are capable of detecting loss of preload, (2) the use of the Bolting Integrity Program is consistent with the recommendations in the GALL Report, and (3) supplementing the inspections performed by the Bolting Integrity Program with inspections performed by the other alternative programs provides a more comprehensive approach to monitoring aging for these components.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.4 Loss of Material Due to General Corrosion

LRA Table 3.3.1, items 3.3.1-57 and 3.3.1-58 address steel piping and components external surfaces exposed to indoor uncontrolled air, outdoor air, and condensation being managed for loss of material due to general corrosion. The LRA credits the Fire Water System Program in addition to the External Surfaces Monitoring Program for carbon steel, gray cast iron, and ductile cast iron piping and fittings, pump casings, strainer bodies, valve bodies, and tanks (retarding chambers) in the fire protection system. The GALL Report recommends GALL AMP XI.M36, "External Surfaces Monitoring," to ensure that these aging effects are adequately managed. The AMR line items cite generic note E. The AMR line items also cite plant-specific note 12, indicating that the Fire Water System Program will be used in addition to the External Surfaces Monitoring Program.

GALL AMP XI.M36 recommends using periodic visual inspections of the external surfaces of steel components to manage these aging effects. In its review of components associated with items 3.3.1-57 and 3.3.1-58 for which the applicant cited generic note E, the staff noted that the applicant credited both the Fire Water System and External Surfaces Monitoring Programs to manage aging for these components in LRA Table 3.3.2-10.

The staff reviewed the applicant's Fire Water System Program and its evaluation is documented in SER Section 3.0.3.2.8. The staff noted that the Fire Water System Program proposes to manage the aging effects of these components through the use of periodic visual inspections to detect corrosion. The staff finds the applicant's proposed program acceptable to manage aging for these components because: (1) the proposed inspection method of periodic visual inspections is the same as that in the GALL Report recommended AMP, and (2) the applicant is using the Fire Water System Program in addition to the External Surfaces Monitoring Program, which provides a more conservative approach to managing this aging effect.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-57 addresses steel piping and components external surfaces exposed to indoor air which are being managed for loss of material due to general corrosion. The LRA credits the Fire Protection Program to manage aging for steel filter housings in the fire protection system. The GALL Report recommends GALL AMP XI.M36, "External Surfaces Monitoring," to ensure that these aging effects are adequately managed. The AMR line item cites generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited. The AMR line item also cites plant-specific note 1, indicating that the Fire Protection Program is substituted to manage the aging effects applicable to this component type, material, and environment combination. GALL AMP XI.M36 recommends using periodic visual inspections of the external surfaces of steel components to manage these aging effects.

The staff reviewed the applicant's Fire Protection Programs and its evaluation is documented in SER Section 3.0.3.2.7. In its review of components associated with item 3.3.1-57 for which the applicant cited generic note E, the staff noted that the Fire Protection Program proposes to manage the aging effects of the steel component's external surfaces through the use of periodic visual inspections. The staff finds the applicant's proposed program acceptable to manage aging for these components because the proposed inspection methods in the Fire Protection Program are the same as those methods recommended by the GALL Report recommended AMP.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-57 addresses steel piping and components external surfaces exposed to indoor air which are being managed for loss of material due to general corrosion. The LRA credits the Fire Protection Program in addition to the External Surfaces Monitoring Program for steel piping and fittings, odorizers, and valve bodies in the fire protection system. The GALL Report recommends GALL AMP XI.M36, "External Surfaces Monitoring," to ensure that these aging effects are adequately managed. The AMR line item cites generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited. The AMR line item also cites plant-specific note 15, indicating that the Fire Protection Program will be used in addition to the External Surfaces Monitoring Program. GALL AMP XI.M36 recommends using periodic visual inspections of the external surfaces of steel components to manage these aging effects.

The staff reviewed the applicant's Fire Protection and External Surfaces Monitoring Programs and its evaluations are documented in SER Sections 3.0.3.2.7 and 3.0.3.1.13, respectively. In its review of components associated with item 3.3.1-57 for which the applicant cited generic note E, the staff noted that the Fire Protection Program proposes to manage the aging effects of the steel component's external surfaces through the use of periodic visual inspections. The staff finds the applicant's proposed program acceptable to manage aging for these components because: (1) the proposed inspection methods in the Fire Protection Program are the same as those recommended by the GALL Report recommended AMP, and (2) the applicant is using the Fire Protection Program in addition to the External Surfaces Monitoring Program, which provides a more conservative approach to managing this aging effect.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-58 addresses steel piping and components external surfaces exposed to indoor uncontrolled air, outdoor air, and condensation being managed for loss of material due to general corrosion. The LRA credits the Fire Protection Program to manage these aging effects for the external surfaces of carbon steel doors and the Fire Protection and External Surfaces Monitoring programs to manage the aging effects for halon gas bottles in the fire protection system. The GALL Report recommends GALL AMP XI.M36, "External Surfaces Monitoring," to ensure that these aging effects are adequately managed. The AMR line items cite generic note E indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited. The AMR line items also cite plant-specific note 1, indicating that the Fire Protection Program is substituted to manage the aging effects applicable to this component type, material, and environment combination.

GALL AMP XI.M36 recommends using periodic visual inspections of the external surfaces of steel components to manage these aging effects. In its review of components associated with item 3.3.1-58 for which the applicant cited generic note E, the staff noted that the applicant credited the Fire Protection Program to manage aging for these components in LRA Table 3.3.2-10.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.7. The staff noted that the Fire Protection Program proposes to manage the aging effects of these components through the use of periodic visual inspections to detect corrosion. The staff finds the applicant's proposed program acceptable to manage aging for these components because the proposed inspection method of periodic visual inspections is consistent with that in the GALL Report recommended AMP and is appropriate to detect loss of material.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.5 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-54 addresses stainless steel piping, piping components, and piping elements exposed to internal condensation which are being managed for loss of material due to pitting and crevice corrosion. The LRA credits the Periodic Inspection Program to manage aging for stainless steel piping, fittings, valve bodies, flow elements, restricting orifices, and thermowells exposed internally to wetted air or gas. The GALL Report recommends GALL AMP XI.M24, "Compressed Air Monitoring," to ensure that these aging effects are adequately managed. The AMR line items cite generic note E, which indicate that the line item is consistent with the GALL Report for the material, environment, and aging effect, but a different AMP is credited. The AMR line items also cite plant-specific note 1, indicating that the Periodic Inspection Program is substituted to manage the aging effects applicable to this component type, material, and environment combination.

GALL AMP XI.M24 recommends performing periodic air quality checks to ensure contaminants are maintained within industry standards, leakage testing to ensure the integrity of the system, and inspections for corrosion. In its review of components associated with item 3.3.1-54 for which the applicant cited generic note E, the staff noted that the applicant credited the Periodic Inspection Program to manage aging for stainless steel components in LRA Tables 3.3.2-4, 3.3.2-15, 3.3.2-17, 3.3.2-20, 3.3.2-21, 3.3.2-29, and 3.3.2-31.

The staff reviewed the applicant's Periodic Inspection Program and its evaluation is documented in SER Section 3.0.3.3.2. The staff noted that the Periodic Inspection Program includes periodic visual inspections of components and ultrasonic wall thickness measurements to detect loss of material; but it does not include any preventive measures, such as air quality checks, which are included in the GALL Report recommended AMP. By letter dated July 12, 2010, the staff issued RAI 3.3.1.54-01, requesting that the applicant explain how these stainless steel components will be adequately managed by the Periodic Inspection Program.

In its response dated July 26, 2010, the applicant stated that the Compressed Air Monitoring Program is not applicable because the components in question are not in systems where internal air quality is maintained and are designed to be subject to the accumulation of moisture and contaminants. The applicant also stated that plant operating experience from several inspections of stainless steel components exposed to internal condensation and wetting with more than 30 years of inservice time indicates that stainless steel performs satisfactorily in this environment with adequate corrosion resistance. The staff finds the applicant's response to RAI 3.3.1.54-01 and its proposal to manage aging for these components using the Periodic Inspection Program acceptable because: (1) the components described above are not exposed to air that is filtered and dried and, therefore, the preventive measures in GALL AMP XI.M24 would not be appropriate; (2) the visual inspections and ultrasonic wall thickness examinations performed by the Periodic Inspection Program are appropriate for detecting the stated aging effects; and (3) the frequency of inspections is consistent with plant operating experience.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-54 addresses stainless steel compressed air system piping, piping components, and piping elements exposed to internal condensation being managed for loss of material due to pitting and crevice corrosion. The LRA credits the Fire Protection Program for managing the aging of stainless steel spray nozzles in the fire protection system. The GALL Report recommends GALL AMP XI.M24, "Compressed Air Monitoring," to ensure that these aging effects are adequately managed. The AMR line items cite generic note E, which indicates that the line item is consistent with the GALL Report for the material, environment, and aging effect, but a different AMP is credited. The AMR line items also cite plant-specific note 1, indicating that the Fire Protection Program is substituted to manage the aging effects applicable to this component type, material, and environment combination. GALL AMP XI.M24 recommends managing aging for compressed air system piping exposed to internal condensation by monitoring and controlling contaminants in the air in order to limit loss of material due to corrosion, and leakage testing to detect loss of material.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.7. The staff noted that the Fire Protection Program includes: (1) external visual inspections of fire barriers, seals, and doors; and (2) external visual inspections and functional testing of the diesel driven fire pump, and halon and CO_2 fire suppression systems. In its review of components associated with item 3.3.1-54 for which the applicant cited generic note E, the staff also noted that the applicant credited the Fire Protection Program to manage aging for stainless steel spray nozzles in LRA Table 3.3.2-10. However, the staff further noted that the Fire Protection Program does not include criteria for inspections of the internal surfaces of components or leakage testing which could detect loss of material for the stainless steel spray nozzles.

By letter dated June 22, 2010, the staff issued RAI 3.3.1-01 requesting that the applicant justify how the Fire Protection Program will manage the aging effect of loss of material due to pitting and crevice corrosion for these components in a wetted air or gas internal environment.

In its response dated July 19, 2010, the applicant stated that the stainless steel spray nozzles are located in an indoor air environment and are inspected during the periodic functional testing of the halon and CO_2 fire suppression systems. The applicant also stated that the internal and external surfaces of the spray nozzles are subject to the same environment and are not subject to condensation or wetting that could cause corrosion. As a result, the applicant revised LRA Table 3.3.2-10 to change the environment for the internal surfaces of the spray nozzles to indoor air, referencing item 3.3.1-94, with generic note A. The staff finds the applicant's response to RAI 3.3.1-01 and its proposal to manage aging for stainless steel spray nozzles in accordance with item 3.3.1-94 acceptable because: (1) the spray nozzles have been appropriately aligned to an alternative line item for exposure of stainless steel components to indoor uncontrolled air, and (2) the spray nozzles are located in an indoor air environment and stainless steel components are not expected to experience aging effects when exposed to indoor air. The staff's concern described in RAI 3.3.1-01 is resolved.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.6 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

LRA Table 3.3.1, item 3.3.1-68 addresses steel piping, piping components, and piping elements exposed to raw water being managed for loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling. The LRA credits the Fire Water System Program to manage aging for gray cast iron (retarding chamber) tanks exposed to raw water in LRA Table 3.3.2-10. The AMR line items cite generic note C.

The staff's evaluation of the Fire Water System Program is documented in SER Section 3.0.3.2.8. The staff noted that the applicant's Fire Water System Program performs wall thickness evaluations of fire protection piping using non-intrusive techniques (e.g., volumetric testing) to identify loss of material due to corrosion. However, it was not clear to the staff whether volumetric inspections performed by the Fire Water System Program to detect loss of material due to corrosion will be performed on the internal surface (specifically the bottom) of the retarding chamber tanks. By letter dated June 14, 2010, the staff issued RAI 3.3.2.10-1, requesting that the applicant clarify if these tanks are included in the sample of fire protection system components that will be volumetrically inspected for wall thickness evaluation to detect loss of material prior to loss of intended function.

In its response dated July 12, 2010, the applicant stated that the retarding chamber tanks are self draining tanks with a capacity of approximately 2 gallons that prevent spurious actuation of the alarm pressure switch. The applicant also stated that the retarding chamber tanks are normally drained, not at system low points, is not in the flowpath of water to the sprinkler heads, and provides system alarm function only. The applicant further stated that the retarding chamber tanks are not included in the sample of components that will be volumetrically inspected. The staff finds the applicant's response to RAI 3.3.2.10-1 and the use of the Fire Water System Program to manage loss of material for the retarding chamber tanks acceptable because the tanks: (1) provide for system alarm function only, (2) are not part of the flowpath of water to the sprinkler heads, and (3) do not contain stagnant water. Therefore, the tanks do not require volumetric testing and are being adequately managed by the system flow testing performed by the Fire Water System Program.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-68 addresses steel piping, piping components, and piping elements exposed to raw water which are being managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling. The LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage aging for various steel (i.e., carbon, galvanized, ductile iron, gray cast iron) components in the fresh water supply, radwaste, and equipment and floor drainage systems. The GALL Report recommends GALL AMP XI.M27, “Fire Water System,” to ensure these aging effects are adequately managed. The AMR line items cite generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment and aging effect, but a different AMP is credited.

GALL AMP XI.M27 recommends that fire protection system piping be subjected to flow testing, and wall thickness evaluations or visual inspections to identify loss of material and fouling. However, the applicant referenced generic note E and cited item 3.3.1-68 for components in systems other than the fire protection system. The staff reviewed all AMR result lines in the GALL Report where steel components exposed to raw water are being managed for loss of material and fouling and noted that there are entries for this combination in other systems; and that those entries recommend GALL AMP XI.M20, “Open-Cycle Cooling Water System” to ensure that these aging effects are adequately managed. The staff also noted that GALL AMP XI.M20 recommends preventive measure including proper selection of materials and coatings, periodic flushes and cleaning, and raw water chemistry control as well as visual inspections and NDE testing for components exposed to open-cycle cooling water. The staff further notes that open-cycle cooling water is water which transfers heat from safety related components to the ultimate heat sink.

The staff reviewed the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and its evaluation is documented in SER Section 3.0.3.1.14. The staff notes that the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program includes inspections of the internal surfaces of a representative sample of components to detect loss of material and fouling when the components become accessible for inspection and at plant-specific intervals based on operating experience. The staff also noted that the components for which the applicant referenced generic note E and cited item 3.3.1-68 are in the fresh water supply, radwaste, and equipment and floor drainage systems and do not include any safety-related components exposed to open-cycle cooling water; therefore, the GALL Report recommended programs are not appropriate to manage aging for these components. The staff finds the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable to manage aging for these components because it includes visual inspections of the internal surfaces of components which are appropriate to detect loss of material and fouling.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.7 Loss of Material due to General, Pitting, Crevice, Galvanic, and Microbiologically-Influenced Corrosion and Fouling

LRA Table 3.3.1, items 3.3.1-77 addresses steel heat exchanger components exposed to raw water which are being managed for loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling. The LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M20, “Open-Cycle Cooling Water System,” to ensure that these aging effects are adequately managed. The associated AMR line item in Table 3.3.2-12, identified as carbon steel piping and fittings in the fresh water supply system, cites generic note E, which indicates that the line item is consistent with the GALL Report for the material, environment, and aging effect, but a different AMP is credited.

GALL AMP XI.M20 recommends to visually monitor the condition of the open-cycle cooling water (or service water) system components and their coated surfaces against aggressive water environment for loss of material. In addition, when necessary, the program performs nondestructive (e.g., UT, eddy current) testing to measure wall thinning and preventive measures (e.g., chemical treatment, system flushing) to assure that aging effects due to MIC, biofouling, and silt are managed for safety-related components within the scope of GL 89-13. Inspections are performed annually or during refueling outages.

In its review of components associated with item 3.3.1-77, for which the applicant cited generic note E, the staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage aging of the referenced carbon steel piping and fittings items through visual inspections during surveillances, maintenance activities, and outages. When the inspections yield evidence for loss of material or fouling that could potentially impair these components’ intended function, the applicant then evaluates the degraded conditions and if warranted, implements its corrective action program.

The staff’s evaluation of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.1.14. The staff notes that the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program includes inspections of the internal surfaces of a representative sampling of components to detect loss of material and fouling when the components become accessible for inspection, and at plant-specific intervals based on operating experience. The staff also notes that the components for which the applicant referenced generic note E and cited item 3.3.1-77 are in the radwaste, and equipment and floor drainage systems and do not include any safety-related components exposed to open-cycle cooling water; therefore, the GALL Report recommended program is not appropriate to manage aging for these components. In its review of components associated with item 3.3.1-77, the staff finds the applicant’s proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because: (1) the components being managed by the program are nonsafety-related and not within the scope of GL 89-13; therefore, the preventive measures in GALL AMP XI.M20 are not appropriate; and (2) its visual inspections are as comprehensive as the GALL Report recommended AMP inspections for this nonsafety-related item in the fresh water supply system.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.3.1, item 3.3.1-77 addresses steel heat exchanger components exposed to raw water which are being managed for loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling. The LRA credits the Fire Water System Program for steel piping and fittings in the fire protection system. The GALL Report recommends GALL AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The AMR line item cites generic note E. The AMR line item also cites plant-specific note 5, indicating that the Fire Water System Program is substituted to manage the aging effects applicable to this component type, material, and environment combination.

GALL AMP XI.M20 relies on implementation of the recommendations of GL 89-13, which includes using preventive measures (i.e., water chemistry control), periodic visual inspections, and performance testing to manage these aging effects. In its review of components associated with item 3.3.1-77 for which the applicant cited note E, the staff noted that the applicant credited the Fire Water System Program to manage aging for these steel components in LRA Table 3.3.2-10.

The staff reviewed the applicant's Fire Water System Program and its evaluation is documented in SER Section 3.0.3.2.8. This GALL Report item recommends the Fire Water System Program to manage loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling of steel piping and piping components exposed to raw water. The staff finds the applicant's proposed program acceptable to manage these aging effects for these components because the components are part of the fire protection system and using the Fire Water System Program is consistent with the recommendations in GALL AMR item VII.G-24.

3.3.2.1.8 Loss of Material due to Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

LRA Table 3.3.1, item 3.3.1-81 addresses copper alloy piping, piping components, and piping elements exposed to raw water which are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling. The LRA credits the Periodic Inspection Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR line items in Tables 3.3.2-9 and 3.3.2-12 cite generic note E, which indicates that the line item is consistent with the GALL Report for the material, environment, and aging effect, but a different AMP is credited.

GALL AMP XI.M20 recommends visually monitoring the condition of the open-cycle cooling water (or service water) system components and their coated surfaces against aggressive water environment for loss of material. In addition, when necessary, the program performs nondestructive (e.g., UT, eddy current) testing to measure wall thinning and preventive measures (e.g., chemical treatment, system flushing) to assure that aging effects due to MIC, biofouling, and silt are managed for safety-related components within the scope of GL 89-13. Inspections are performed annually or during refueling outages.

In its review of components associated with item 3.3.1-81 for which the applicant cited generic note E, the staff noted that the Periodic Inspection Program proposes to manage aging of the referenced copper alloy piping, piping components, and piping elements through visual inspections and UT wall thickness measurements. When the inspections yield evidence for loss of material or fouling that could potentially impair these components' intended function, then the applicant will evaluate the degraded conditions and, if warranted, implement its corrective action program.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff notes that the applicant's Periodic Inspection Program includes focused visual inspections and UT wall thickness measurements that will detect the presence and extent of loss of material aging effect. The focused visual inspections will also detect the presence and extent of fouling. The staff also notes that the components for which the applicant referenced generic note E and cited item 3.3.1-81 are in the fresh water supply system and equipment and floor drainage systems, and do not include any safety-related components exposed to open-cycle cooling water; therefore, the GALL Report recommended program is not appropriate to manage aging for these components. In its review of components associated with item 3.3.1-81, the staff finds the applicant's proposal to manage aging using the Periodic Inspection Program acceptable because: (1) the components being managed by the program are nonsafety-related and not within the scope of GL 89-13; therefore, the preventive measures in GALL AMP XI.M20 are not appropriate; and (2) its visual inspections are as comprehensive as the GALL Report recommended AMP inspections for this nonsafety-related item in the fresh water supply system.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.9 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

LRA Table 3.3.1, item 3.3.1-72 addresses steel HVAC ducting and components internal surfaces exposed to condensation being managed for loss of material due to general, pitting, crevice, and microbiologically-influenced (for drip pans and drain lines) corrosion. The LRA credits the Fire Protection Program for galvanized steel damper housings in the fire protection system exposed internally to wetted air or gas. The GALL Report recommends GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to ensure that these aging effects are adequately managed. The AMR line items cite generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited. The AMR line items also cite plant-specific note 1, indicating that the Fire Protection Program is substituted to manage the aging effects applicable to this component type, material, and environment combination.

GALL AMP XI.M38 recommends performing inspections of the internal surfaces of piping and components to manage loss of material when the components internal surfaces are exposed for maintenance and testing activities. In its review of components associated with item 3.3.1-72 for which the applicant cited generic note E, the staff noted that the applicant credited the Fire Protection Program to manage aging for galvanized steel damper housings in LRA Table 3.3.2-10.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.7. The staff noted that the Fire Protection Program includes periodic visual inspections and functional testing of fire dampers at least once every refueling cycle. The staff finds the applicant's Fire Protection Program acceptable to manage aging for galvanized steel damper housings in the fire protection system because periodic visual inspections and functional testing are capable of detecting loss of material for the specified components, and the method and frequency of periodic visual inspections performed by the program are consistent with those performed by the GALL Report recommended AMP.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.10 Increased Hardness, Shrinkage, and Loss of Strength Due to Weathering

LRA Table 3.3.1, item 3.3.1-61 addresses elastomer fire barrier penetration seals exposed to air – outdoor or air – indoor that is not controlled. These penetration seals are being managed to address increased hardness, shrinkage, and loss of strength due to weathering. In LRA Tables 3.5.2-2, 3.5.2-3, 3.5.2-8, and 3.5.2-12, the applicant associated item 3.1.1-61 with elastomer compressible joints and seals (seismic gaps) in the auxiliary building control/diesel generator area, the auxiliary building service/radwaste area, the reactor building, and the turbine building, respectively. The GALL Report recommends the Fire Protection Program to manage aging of components associated with item 3.1.1-61. However, for the elastomer compressible joints and seals for seismic gaps, the applicant credited the Structures Monitoring Program to manage the aging effect.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.16. In its review of components associated with LRA item 3.3.1-61 for which the applicant assigned generic note E, the staff noted that the Structures Monitoring Program proposes to manage hardening, shrinkage, and loss of sealing for elastomer components within its scope through the use of visual inspections. The staff noted that the GALL Report recommends GALL AMP XI.M26, "Fire Protection," for aging management of components, materials, and environments associated with Table 3.3.1, item 3.3.1-61. The staff further noted that GALL AMP XI.M26 credits visual inspection by qualified inspectors with managing aging in those components. The staff noted that for elastomer components, the monitoring methods implemented by the Structures Monitoring Program are the same as in GALL AMP XI.M26 and there are no substantive differences between the other program elements as compared to the GALL Report. The staff finds that the applicant's proposal to use the Structures Monitoring Program to manage aging of elastomer compressible joints and seals (seismic gaps) acceptable because the program performs visual inspections that are capable of detecting degradation of elastomer components within its scope and implements corrective actions if degradation is found, through the applicant's corrective action program, prior to loss of the component's intended function(s).

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.11 No Aging Effects Requiring Management

LRA Table 3.3.1, item 3.3.1-98 addresses steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to dried air and states that these components have no AERM. The LRA credits the Compressed Air Monitoring Program to manage steel and stainless steel piping, fitting, valve bodies, accumulators, hoses, and receiver tanks exposed internally to dry air or gas. The GALL Report states that these components have no AERMs and no AMP is recommended to ensure that these aging effects are adequately managed. The AMR line items cite generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited. The AMR line items also cite plant-specific note 1, indicating that the Compressed Air Monitoring Program is applied to confirm the internal environment remains sufficiently dry to preclude aging effects.

In its review of components associated with item 3.3.1-98 for which the applicant cited generic note E, the staff noted that the applicant credited the Compressed Air Monitoring Program to manage aging for steel and stainless steel components in LRA Tables 3.3.2-3, 3.3.2-19, and 3.3.2-23. The staff reviewed the applicant's Compressed Air Monitoring Program and its evaluation is documented in SER Section 3.0.3.1.10. The staff noted that the Compressed Air Monitoring Program includes periodic air quality checks to ensure dew point, particulates, and contaminants are maintained within industry standards, leak testing, and visual inspections. The staff finds the applicant's Compressed Air Monitoring Program acceptable to manage aging for steel and stainless steel components exposed to dry air or gas because periodic air quality checks will ensure the environment remains dry, and the leak testing and visual inspections will ensure aging is not occurring.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

LRA Section 3.3.2.2 provides further evaluation of aging management, as recommended by the GALL Report, for the auxiliary systems components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- reduction of heat transfer due to fouling
- cracking due to SCC
- cracking due to SCC and cyclic loading
- hardening and loss of strength due to elastomer degradation
- reduction of neutron-absorbing capacity and loss of material due to general corrosion
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion

- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling
- loss of material due to pitting and crevice corrosion
- loss of material due to pitting, crevice, and galvanic corrosion
- loss of material due to pitting, crevice, and microbiologically-influenced corrosion
- loss of material due to wear
- loss of material due to cladding breach

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations to determine whether they adequately address those issues. In addition, the staff reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.3.2.2. The staff's review of the applicant's further evaluation follows.

3.3.2.2.1 Cumulative Fatigue Damage

LRA Section 3.3.2.2.1 addresses the applicant's aging management review basis for managing cumulative fatigue damage in auxiliary system components that were designed analyzed to applicable design analysis criteria in the ASME Code Section III, Articles NC-3000 or ND-3000 (as applicable to Code Class 2 or 3 components, respectively) or in the ANSI B31.1 Code, and for which implicit fatigue analyses were required. In this LRA section, the applicant stated that the evaluation of fatigue is a TLAA as defined in 10 CFR 54.3, and that the TLAAs are evaluated in accordance with the TLAA acceptance criteria in 10 CFR 54.21(c)(1). The applicant stated that the HCGS piping designed to ASME Code Section III requirements for Class 2 or 3 components or to the ANSI B31.1 design code were analyzed using an implicit fatigue analysis that assumes a reduction in the component's allowable secondary stress range if more than 7,000 full-range thermal cycles are expected over the component's design lifetime.

In LRA Table 3.3.1, the applicant stated that the AMR item 3.3.1-1 for managing of cumulative fatigue damage in the applicant's cranes and hoists system components are consistent with the staff's AMR item recommendations in AMR item 1 of Table 3 in the GALL Report, Volume 1, Revision 1. The applicant stated that AMR item 3.3.1-2 for managing of cumulative fatigue damage in applicable heat exchangers and piping, piping components, and piping elements in the HPCI, main steam, RCIC, and RWCU systems are consistent with the staff's AMR item recommendations in AMR item 2 of the GALL Report, Volume 1, Table 3. The applicant stated that, for these AMRs, cumulative fatigue damage in the components will be managed using a TLAA, and that LRA Section 4.3.4 describes and evaluates implicit fatigue analysis-based TLAA for these components.

The staff reviewed LRA Section 3.3.2.2.1 against the criteria in SRP-LR Section 3.3.2.2.1, which states that fatigue of ESF components is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1) and in accordance with the staff's recommended acceptance criteria and review procedures for reviewing these TLAAs in SRP-LR Section 4.3, "Metal Fatigue Analysis."

The staff also reviewed LRA Section 3.3.2.2.1 and the AMRs discussed in this section against the staff's AMR items for evaluating cumulative fatigue damage in the GALL Report.

With regard to the applicant's metal fatigue AMR item 3.3.1-1, the staff noted that AMR item 1 in Table 3 of the GALL Report, Volume 1 and AMR item VII.B-2 in the GALL Report, Volume 2 identify that cumulative fatigue damage is an applicable aging effect for steel cranes or structural girders exposed to air. The staff also noted that these GALL Report AMRs recommend that the TLAA on metal fatigue be used to manage the impact of cumulative fatigue damage in these components. The staff noted that, in conformance with this recommendation, the applicant included an applicable line item in LRA Table 3.3.2-8 for steel cranes or structural girders that received ASME Code Section III CUF or ANSI B31.1 design code analysis calculations. The staff noted that the applicant credited the TLAA analysis in LRA Section 4.7.1 with the management of cumulative fatigue damage in these components. The staff found that the applicant's AMR assessment is in conformance with the recommendations both in the SRP-LR and in AMR item 1 of the GALL Report, Volume 1, Table 3 and AMR item VII.B-2 in the GALL Report, Volume 2. Based on this review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of steel cranes or structural girders to be acceptable because it is in conformance with the recommendations in SRP-LR Section 3.3.2.2.1 and the GALL Report AMR items that are invoked by this SRP-LR section. The staff evaluates the TLAA analysis for the support skirt and attachment welds component in SER Section 4.7.1.

With regard to the applicant's metal fatigue AMR item 3.3.1-2, the staff noted that AMR item 2 in Table 3 of the GALL Report, Volume 1 and AMR item VII.E3-14 in the GALL Report, Volume 2 identify that cumulative fatigue damage is an applicable aging effect for steel and stainless steel piping, piping components, piping elements, and heat exchanger components. The staff also noted that these GALL Report AMRs recommend that the TLAA on metal fatigue be used to manage the impact of cumulative fatigue damage in these components. The staff noted that, in conformance with this recommendation, the applicant included an applicable line item in LRA Tables 3.2.2-4, 3.2.2-6, 3.3.2-24, and 3.4.2-4 for stainless steel piping, piping components, piping elements, and heat exchanger components that received ASME Code Section III CUF or ANSI B31.1 design code analysis calculations. The staff noted that the applicant credited the TLAA analysis in LRA Section 4.3.4 with the management of cumulative fatigue damage in these components. The staff found that the applicant's AMR assessment is in conformance with the recommendations in both the SRP-LR and in AMR item 2 of the GALL Report, Volume 1, Table 3 and AMR item VII.E3-14 in the GALL Report, Volume 2. Based on this review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of piping, piping components, piping elements, and heat exchanger components to be acceptable because it is in conformance with the recommendations in SRP-LR Section 3.3.2.2.1 and the GALL Report AMR items that are invoked by this SRP-LR section. The staff evaluates the TLAA analysis for the support skirt and attachment welds component in SER Section 4.3.4.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.1 criteria. For those items that apply to LRA Section 3.3.2.2.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.2 Reduction of Heat Transfer Due to Fouling

The staff reviewed LRA Section 3.3.2.2.2 against the criteria in SRP-LR Section 3.3.2.2.2.

LRA Section 3.3.2.2.2 refers to LRA Table 3.3.1, item 3.3.1-3 and addresses stainless steel heat exchanger tubes exposed to treated water which are being managed for reduction in heat transfer due to fouling by the Water Chemistry and One-Time Inspection Programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry Program manages the reduction of heat transfer for these components in the fuel pool cooling and RHR systems, and that a One-Time Inspection Program will be implemented to verify the effectiveness of the Water Chemistry Program. The LRA also states that these components have been evaluated with the closed-cycle cooling water system, which provides the cooling water to these heat exchangers.

The staff reviewed LRA Section 3.3.2.2.2 against the criteria in SRP-LR Section 3.3.2.2.2, which states that reduction of heat transfer due to fouling could occur for stainless steel heat exchanger tubes exposed to treated water. The SRP-LR also states that the existing program relies on control of water chemistry to manage reduction of heat transfer due to fouling; however, since control may have been inadequate, the effectiveness of the Water Chemistry Program should be verified. The SRP-LR also states that a one-time inspection is an acceptable method to verify the effectiveness of the Water Chemistry Program to ensure that reduction of heat transfer does not occur.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection Program is documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. In its review of components associated with item 3.3.1-3, the staff finds the applicant's proposal to manage aging using the above programs acceptable because the Water Chemistry Program provides for periodic sampling of treated water to maintain contaminants at acceptable limits to preclude loss of heat transfer due to fouling, and the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program by including inspections at appropriate locations, including low or stagnant flow areas.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.2 criteria. For those line items that apply to LRA Section 3.3.2.2.2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.3 Cracking Due to Stress-Corrosion Cracking

The staff reviewed LRA Section 3.3.2.2.3 against the criteria in SRP-LR Section 3.3.2.2.3.

(1) LRA Section 3.3.2.2.3.1 refers to Table 3.3.1, item 3.3.1-4 and addresses cracking due to SCC. The applicant stated that this aging effect is not applicable because the stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution are maintained at a temperature less than 60 °C (140 °F) at HCGS.

SRP-LR Section 3.3.2.2.3.1 states that cracking due to SCC could occur in the stainless steel piping, piping components, and piping elements of the BWR standby liquid control system that are exposed to sodium pentaborate solution greater than 60 °C (140 °F).

The staff reviewed the applicant's UFSAR and finds that SRP-LR Section 3.3.2.2.3, item 1 is not applicable to HCGS because the stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution are maintained at a temperature less than 60 °C (140 °F) at HCGS, and the staff guidance in this SRP-LR section is only applicable to BWR stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution greater than 60 °C (140 °F).

(2) LRA Section 3.3.2.2.3, item 2 refers to LRA Table 3.3.1-5 and addresses stainless steel and stainless clad steel heat exchanger components exposed to treated water greater than 60°C (140 °F) which are being managed for cracking due to SCC by the Water Chemistry and One-Time Inspection Programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry Program provides for monitoring and controlling water chemistry in accordance with the EPRI BWRVIP BWR Water Chemistry Guidelines which prevent or mitigate cracking due to SCC. The applicant also stated that the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program in the RWCU system.

The staff reviewed LRA Section 3.3.2.2.3, item 2 against the criteria in SRP-LR Section 3.3.2.2.3, item 2, which states that cracking due to SCC could occur in stainless steel and stainless clad steel heat exchanger components exposed to treated water greater than 60 °C (140 °F). The SRP-LR also states that the GALL Report recommends further evaluation of a plant-specific AMP, using acceptance criteria described in Branch Technical Position RLSB-1, to ensure that these aging effects are adequately managed.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection Programs is documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. In its review of the applicant's One-Time Inspection Program, the staff noted that the heat exchanger components will be subjected to enhanced visual inspection and/or volumetric inspection to detect cracking. Also, the applicant will use representative sampling to detect aging of components with similar environments, and any cracking discovered during these inspections will be evaluated through the corrective action program. In its review of components associated with item 3.3.1-5, the staff finds the applicant's proposal to manage aging using the above programs acceptable because monitoring and controlling water chemistry in accordance with the cited standards will minimize cracking due to SCC, and the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.3, item 2 criteria. For those line items that apply to LRA Section 3.3.2.2.3, item 2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(3) LRA Section 3.3.2.2.3.3 is referenced by LRA Table 3.3.1, item 3.3.1-6 and addresses stainless steel diesel engine exhaust expansion joints exposed to diesel exhaust which are being managed for SCC by the Periodic Inspection Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the program includes focused visual inspections to evaluate if material degradation is occurring which could result in a loss of component intended function, as a result of exposure to the environmental condition.

The staff reviewed LRA Section 3.3.2.2.3.3 against the criteria in SRP-LR Section 3.3.2.2.3, item 3, which states that cracking due to SCC could occur in stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The SRP-LR recommends a plant-specific AMP to manage SCC. In addition, a further evaluation of the plant-specific program for these components is recommended to ensure that the aging effect is adequately managed. GALL Report item VII.H2-1 also recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff notes that the program is acceptable because it requires visual inspections and nondestructive volumetric examinations to ensure that the existing environmental conditions are not causing environmental degradation that could result in a loss of the component's intended function. In its review of components associated with item 3.3.1-6, the staff finds the applicant's proposal to manage aging using the Periodic Inspection Program acceptable because it requires inspection techniques that will be able to properly manage the SCC aging effect.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.3.3 criteria. For those line items that apply to LRA Section 3.3.2.2.3.3, the staff determines that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on a review of the programs identified above, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.3. For those line items that apply to LRA Section 3.3.2.2.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.4 Cracking Due to Stress-Corrosion Cracking and Cyclic Loading

The staff reviewed LRA Section 3.3.2.2.4 against the criteria in SRP-LR Section 3.3.2.2.4.

(1) LRA Section 3.3.2.2.4.1 refers to Table 3.3.1, item 3.3.1-7 and addresses cracking due to SCC and cyclic loading. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.3.2.2.4.1 states that cracking due to SCC and cyclic loading could occur in stainless steel PWR non-regenerative heat exchanger components exposed to treated borated water greater than 60 °C (140 °F) in the chemical and volume control system. SRP-LR Table 3.3-1 identifies item 7 applicable to PWRs.

The staff verified that SRP-LR Section 3.3.2.2.4.1 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR stainless steel non-regenerative heat exchanger components exposed to treated borated water greater than 60 °C (140 °F).

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.3.2.2.4.1 do not apply to HCGS because the guidance is applicable to PWRs.

(2) LRA Section 3.3.2.2.4.2 refers to Table 3.3.1, item 3.3.1-8 and addresses cracking due to SCC and cyclic loading. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.3.2.2.4.2 states that cracking due to SCC and cyclic loading could occur in stainless steel PWR regenerative heat exchanger components exposed to treated borated water greater than 60 °C (140 °F) in the chemical and volume control system. SRP-LR Table 3.3-1 identifies item 8 as applicable to PWRs.

The staff verified that SRP-LR Section 3.3.2.2.4.2 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR stainless steel regenerative heat exchanger components exposed to treated borated water greater than 60 °C (140 °F).

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.3.2.2.4.2 do not apply to HCGS because the guidance is applicable to PWRs.

(3) LRA Section 3.3.2.2.4.3 refers to Table 3.3.1, item 3.3.1-9 and addresses cracking due to SCC and cyclic loading. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.3.2.2.4.3 states that cracking due to SCC and cyclic loading could occur in the stainless steel pump casing for the PWR high-pressure pumps in the chemical and volume control system. SRP-LR Table 3.3-1 identifies item 9 as applicable to PWRs.

The staff verified that SRP-LR Section 3.3.2.2.4.3 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR stainless steel high-pressure pump casings in PWR chemical and volume control systems.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.3.2.2.4.3 do not apply to HCGS because the guidance is applicable to PWRs.

(4) LRA Section 3.3.2.2.4.4 refers to Table 3.3.1, item 3.3.1-10 and addresses cracking due to SCC and cyclic loading. The applicant stated that this aging effect is not applicable because HCGS does not have any high-strength bolting in the auxiliary system.

SRP-LR Table 3.3-1, item 10 has a related item A-104 as evaluated in Chapter VII.E1 of the GALL Report. Chapter VII.E1 of the GALL Report discusses a portion of the PWR chemical and volume control system and its aging effect to cracking due to SCC and cyclic loading.

The staff reviewed the applicant's UFSAR and finds that SRP-LR Section 3.3.2.2.4, item 4 is not applicable to HCGS because HCGS does not have any high-strength bolting in the auxiliary system and the staff guidance in this SRP-LR section is only applicable to high-strength steel closure bolting exposed to air with steam or water leakage.

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.4 criteria. For those line items that apply to LRA Section 3.3.2.2.4, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

(1) LRA Section 3.3.2.2.5.1 refers to Table 3.3.1, item 3.3.1-11 and addresses elastomer seals and components in the filtration, recirculation, and ventilation system; the control room and control area HVAC system; the reactor building ventilation system; the remote shutdown panel room HVAC system; the service water intake ventilation system; and the standby diesel generator area ventilation system exposed to air – indoor (external) or to air or gas – wetted (external) environments. The applicant stated that hardening and loss of strength in these components will be managed by the Periodic Inspection Program. The applicant also stated that compressible joints in the reactor building are aligned to item 3.3.1-11 based on material, environment, and aging effect and that for these components, the Structures Monitoring Program will be used to manage hardening and loss of strength. The applicant addressed the further evaluation requirement by stating that the Periodic Inspection Program is used to manage aging effects of components that are not covered by other AMPs, including external and internal surfaces of non-steel components, and that the Periodic Inspection Program includes visual inspections and physical manipulation of elastomer components. The applicant also stated that the Structures Monitoring Program includes visual inspections of elastomer components to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended function.

The staff reviewed LRA Section 3.3.2.2.5.1 against the criteria in SRP-LR Section 3.3.2.2.5.1, which states that hardening and loss of strength due to elastomer degradation could occur in elastomer seals and components of heating and ventilation systems exposed to air – indoor uncontrolled. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

The staff reviewed the applicant's Periodic Inspection Program and its evaluation is documented in SER Section 3.0.3.3.2. In its review of components associated with LRA item 3.3.1-11 for which the applicant assigned generic note E, the staff noted that the Periodic Inspection Program is a plant-specific program that proposes to detect the aging of elastomer door seals and flexible connections through the use of visual inspections and physical manipulations. The staff finds the applicant's proposal to manage aging of elastomer components in heating and ventilation systems using the Periodic Inspection Program acceptable because: (1) the program performs visual inspections and physical manipulations that are capable of detecting hardening and loss of strength in elastomer components, and (2) the program initiates corrective actions, implemented through the applicant's corrective action program, if indications of age-related degradation are found.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.16. In its review of components associated with LRA item 3.3.1-11 for which the applicant assigned generic note E, the staff noted that the Structures Monitoring Program includes monitoring elastomer components within its scope for hardening, shrinkage, loss of sealing, or loss of strength. The staff notes that for the inflatable pool seal in Table 3.5.2-8, it is not practical to perform physical manipulation of the elastomer due to it being in service, but also notes that visual inspection is adequate because it would detect air bubbles if the seal should be degrading. The staff finds that the applicant's proposal to manage aging of elastomer compressible joints and seals (inflatable pool seals) in the reactor building with the Structures Monitoring Program acceptable because the program: (1) performs visual inspections that are capable of detecting degradation of elastomer components within its scope and (2) implements corrective actions if degradation is found, through the applicant's corrective action program, prior to loss of the component's intended function(s).

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.5.1 criteria. For those line items that apply to LRA Section 3.3.2.2.5.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.3.2.2.5.2 refers to Table 3.3.1, item 3.3.1-12 and addresses elastomer compressible joints and seals (inflatable pool seals) in the reactor building exposed to treated water. The applicant stated that compressible joints and seals (inflatable pool seals) in the reactor building are aligned to item 3.3.1-12 based on material, environment, and aging effect and that for these components, the Structures Monitoring Program will be used to manage hardening and loss of strength. The applicant addressed the further evaluation requirement by stating that the Structures Monitoring Program includes visual inspections of elastomer components to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended function.

The staff reviewed LRA Section 3.3.2.2.5.2 against the criteria in SRP-LR Section 3.3.2.2.5.2, which states that hardening and loss of strength due to elastomer degradation could occur in elastomer linings of the filters, valves, and ion exchangers in spent fuel pool cooling and cleanup systems (BWR and PWR) exposed to treated water or to treated borated water. The GALL Report recommends that a plant-specific AMP be evaluated to determine and assess the qualified life of the linings in the environment to ensure that these aging effects are adequately managed.

Based on information available in the LRA, the staff was unable to determine whether the applicant had assessed the qualified life of the inflatable pool seals, as recommended in the SRP-LR for components aligned with Table 3.3.1, item 3.3.1-12. By letter dated July 9, 2010, the staff issued RAI 3.3.2.2.5.2 requesting that the applicant: (1) clarify whether it has determined a qualified life for the compressible joint seals aligned with item 3.3.1-12, and (2) explain how visual inspection by the Structures Monitoring Program will detect hardening and loss of strength adequate to ensure that the compressible joint seals continue to perform their intended function during the period of extended operation.

In its response dated June 6, 2010, the applicant stated that it has determined that these components, inflatable pool seals exposed to treated water and air – indoor environment which include the reactor well to dryer separator pool gate seal, spent fuel pool to the reactor cavity gate seals, and spent fuel pool to cask storage pool gate seals, are not subject to an AMR. The applicant also stated that the basis for the reactor well to dryer separator pool gate seal not being within scope is that: (1) it would only be used during refueling outages if it becomes necessary to drain the reactor cavity without draining the dryer separator pool; (2) this function has not been, nor is planned to be, used; (3) the seal is not associated with the spent fuel storage pool; and (4) the seal has no intended function for license renewal. The LRA is being revised to remove these components. The applicant further stated that the other two seals are replaced on a 10 year basis.

The staff finds the applicant's response acceptable because the seals either do not perform a license renewal function or they are not long-lived passive items. The staff's concern described in RAI 3.3.2.2.5.2 is resolved.

On the basis of its review, the staff finds that the applicant has appropriately determined that these components do not require an AMP, as required by 10 CFR 54.4 and 10 CFR 54.21(a)(1)(ii).

Based on a review of the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.5 criteria. For those line items that apply to LRA Section 3.3.2.2.5, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.6 Reduction of Neutron-Absorbing Capacity and Loss of Material Due to General Corrosion

LRA Section 3.3.2.2.6 is associated with LRA Table 3.3.1, item 3.3.1-13 and addresses the neutron-absorbing sheets, made of Boral or boron steel, in spent fuel storage racks exposed to treated or treated borated water which are being managed for reduction of neutron-absorbing capacity and loss of material due to general corrosion by the Boral Monitoring Program and Water Chemistry Program.

The staff reviewed LRA Section 3.3.2.2.6 against the criteria in SRP-LR Section 3.3.2.2.6, which states that reduction of neutron-absorbing capacity and loss of material due to general corrosion could occur for neutron-absorbing sheets, made of Boral or boron steel, in spent fuel storage racks exposed to treated or treated borated water. The SRP-LR also states that the GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

The staff notes that the applicant has plant-specific AMPs for Boral and water chemistry that are reviewed in SER Sections 3.0.3.3.5 and 3.0.3.2.1, respectively. In its review of components associated with item 3.3.1-13, the staff finds the applicant's proposal to manage aging using the Boral Monitoring Program and Water Chemistry Program acceptable because it is consistent with the GALL Report.

Based on the programs identified, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.6 criteria. For those line items that apply to LRA Section 3.3.2.2.6, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.7 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.3.2.2.7 against the criteria in SRP-LR Section 3.3.2.2.7.

(1) LRA Section 3.3.2.2.7.1 is associated with Table 3.3.1, item 3.3.1-14 and addresses steel piping, piping components, and piping elements exposed to lubricating oil in the CRD system and standby diesel generators and auxiliary systems which are being managed for loss of material due to general, pitting, and crevice corrosion by the Lubricating Oil Analysis and One-Time Inspection Programs. The applicant addressed the further evaluation requirements by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program. The applicant also stated that items 3.3.1-15 and 3.3.1-16 do not apply because HCGS does not have a reactor coolant pump oil collection system or a reactor coolant pump oil collection system tank. The staff noted that a search of the applicant's UFSAR showed that there was no reactor coolant pump oil collection system listed.

The staff reviewed LRA Section 3.3.2.2.7.1 against the criteria in SRP-LR Section 3.3.2.2.7, item 1, which states that loss of material due to general, pitting, and crevice corrosion could occur for steel piping, piping components, and piping elements, including the tubing, valves, and tanks in the reactor coolant pump oil collection system, exposed to lubricating oil (as part of the fire protection system). The SRP-LR also states that the existing program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring or is progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's Lubricating Oil Analysis and One-Time Inspection Programs and its evaluations are documented in SER Sections 3.0.3.2.13 and 3.0.3.1.11, respectively. In its review of components associated with LRA item 3.3.1-14, the staff finds the applicant's proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection Programs acceptable because: (1) the applicant will perform sufficient inspections for each material-environment combination to provide an overall assessment of any aging degradation that may be occurring; (2) the selection of inspections will consider materials, operating environments, industry and plant-specific operating experience, engineering evaluations of equipment performance, and susceptibility to aging due to time in service, severity of operating conditions, and lowest design margins; (3) recurring surveillance and maintenance activities provide the ability to detect aging of the material-environment combination prior to loss of function; and (4) inspection results will be trended.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.7, item 1 criteria. For those line items that apply to LRA Section 3.3.2.2.7.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.3.2.2.7 is referenced by LRA Table 3.3.1, item 3.3.1-17 and addresses steel piping, piping components, and piping elements exposed to treated water which are being managed for loss of material due to general, pitting, and crevice corrosion. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will implement its One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage loss of material due to general, pitting, and crevice corrosion of the steel piping, piping components, piping elements, heat exchanger components and tanks exposed to treated water at select locations and systems (control area chilled water system, CRD system, fuel handling and storage system, fuel pool cooling and cleanup system, primary containment, RWCU system, standby diesel generators and auxiliary systems, standby liquid control system, and torus water cleanup system).

The staff reviewed LRA Section 3.3.2.2.7, item 2 against the criteria in SRP-LR Section 3.3.2.2.7, item 2, which states that: (1) loss of material due to general, pitting, and crevice corrosion could occur in steel piping, piping components, and piping elements in the BWR RWCU and shutdown cooling systems exposed to treated water; (2) the existing AMP relies on monitoring and control of water chemistry to mitigate corrosion; and (3) control of water chemistry does not preclude corrosion at locations of stagnant flow conditions. The effectiveness of the water chemistry program, therefore, should be verified using a one-time inspection to ensure that corrosion does not occur. The GALL Report recommends a one-time inspection of select components at susceptible locations as an acceptable method to verify the effectiveness of the Water Chemistry Program and ensure that an aging effect is not occurring or is progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. The staff finds this combination of programs acceptable to manage aging for these components because the programs: (1) provide for periodic sampling of treated water to maintain contaminants at acceptable limits to preclude loss of material due to general, pitting, and crevice corrosion; and (2) will perform one-time inspections of steel, piping components, piping elements, heat exchanger components and tanks exposed to treated water.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.7, item 2 criteria. For those line items that apply to LRA Section 3.3.2.2.7, item 2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(3) LRA Section 3.3.2.2.7.3 refers to LRA Table 3.3.1, item 3.3.1-18 and addresses stainless steel and steel diesel engine exhaust piping and components exposed to diesel exhaust which are being managed for loss of material due to pitting and crevice corrosion by the Periodic Inspection and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the programs include focused visual inspections to evaluate if material degradation occurs that results in a loss of component intended function as a result of exposure to the environmental condition.

The staff reviewed LRA Section 3.3.2.2.7.3 against the criteria in SRP-LR Section 3.3.2.2.7, item 3, which states that loss of material could occur in stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The SRP-LR recommends a plant-specific AMP to manage the loss of material aging effect. In addition, a further evaluation of the plant-specific program for these components is recommended to ensure that the aging effect is adequately managed. GALL Report item VII.H2-2 also recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

The staff's evaluations of the applicant's Periodic Inspection and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs are documented in SER Sections 3.0.3.3.2 and 3.0.3.1.14, respectively. The staff notes that the programs are acceptable because they require visual inspections and nondestructive volumetric examinations to ensure that the existing environmental conditions are not causing environmental degradation that could result in a loss of the component's intended function. In its review of components associated with item 3.3.1-18, the staff finds the applicant's proposal to manage aging using the Periodic Inspection and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs acceptable because the inspection techniques in these two programs will be able to properly manage the loss of material due to pitting and crevice corrosion.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.7, item 3 criteria. For those line items that apply to LRA Section 3.3.2.2.7.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.7 criteria. For those line items that apply to LRA Section 3.3.2.2.7, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.8 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

The staff reviewed LRA Section 3.3.2.2.8 against the criteria in SRP-LR Section 3.3.2.2.8.

LRA Section 3.3.2.2.8 is associated with Table 3.3.1, item 3.3.1-19 and addresses loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion in steel piping, piping components, and piping elements with or without coating or wrapping in the fire protection and service water systems exposed to soil. The applicant stated that these items will be managed by the Buried Piping Inspection Program.

The staff reviewed LRA Section 3.3.2.2.8 against the criteria in SRP-LR Section 3.3.2.2.8, which states that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion could occur in steel piping, piping components, and piping elements with or without coating or wrapping in a soil environment. The SRP-LR also states that the effectiveness of the buried piping and tanks inspection program should be verified to evaluate the applicant's inspection frequency and operating experience with buried components, ensuring that loss of material does not occur.

The staff reviewed the LRA AMR items associated with Table 3.3.1, item 3.3.1-19 and noted that for the items that are consistent with the GALL Report for material, environment, and aging effect but a different AMP is credited (generic note E) in Table 3.3.2-10, the applicant will use the Aboveground Steel Tanks Program to manage the loss of material due to pitting, crevice, and microbiologically-influenced corrosion for the steel tanks in the fire protection system. The staff reviewed the applicant's Aboveground Steel Tanks Program, The staff's evaluation is documented in and its evaluation is documented in SER Section 3.0.3.2.9. The staff finds the use of the Aboveground Steel Tanks Program acceptable because it credits the application of paint as a corrosion preventive measure and requires periodic visual inspections of the accessible tank outer surface and wall-thickness measurements of the inaccessible tank bottom external surface by UT to ensure that loss of material will be adequately managed.

The staff reviewed the LRA AMR items associated with Table 3.3.1, item 3.3.1-19 and noted that for the items that are consistent with the GALL Report for material, environment, and aging effect but a different AMP is credited (generic note E) in Tables 3.5.2-1, 3.5.2-2, 3.5.2-3, 3.5.2-5, 3.5.2-8, 3.5.2-11, 3.5.2-12, and 3.5.2-13, the applicant will use the Structures Monitoring Program to manage loss of material due to pitting, crevice, and microbiologically-influenced corrosion for the steel piles in the auxiliary boiler building, fire water pump house, switchyard, and yard structures and for the steel and galvanized steel penetration sleeves in the auxiliary building control and diesel generator and service and radwaste areas, fire water pump house, reactor building, turbine building, and yard structures. The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.16.

For component type piles as contained in the above AMR line items, LRA Section 3.5.2.2.2.2, item 3 states that:

> Degradation of piles or foundation mats will manifest in settlement distortion or cracking, and accessible concrete examinations will detect cracks and distortion of Groups 1 and 3 structures. Studies have shown that steel piles driven into undisturbed natural soil are not appreciably affected by corrosion due to the oxygen deficiency in soil at a few feet below grade. Piles driven into disturbed soil, have been shown to experience only minor to moderate corrosion. In either case the observed loss of material due to corrosion was not considered significant enough to impact the intended function of the piles, which is consistent with NUREG-1557. The condition of the accessible and above grade concrete are used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function. However inaccessible concrete for Groups 1 and 3 structures will be inspected for cracking and distortion due to settlement if excavated for any reason as required by the Structures Monitoring Program.

The staff finds the use of the Structures Monitoring Program acceptable for managing the aging effects associated with these piles because the program inspects the concrete structures for indications of deterioration and distress, including cracking as defined in ACI 201.1R at a frequency not to exceed 5 years.

Due to potential accessibility constraints associated with the penetration sleeves being located in a groundwater or soil environment as contained in the above AMR line items, the staff was unclear how the Structures Monitoring Program, which is primarily a visual-based program, will be used to address the structure and aging effect combinations during the period of extended operation. By letter dated June 7, 2010, the staff issued RAI 3.5.2.1-1 requesting that the applicant describe how the Structures Monitoring Program meets GALL Report recommended programs and how the AMP will be used to manage aging effects, including a discussion of preventive measure requirements.

In its response dated June 29, 2010, the applicant stated that: (1) the penetration sleeves were aligned to GALL Report item 3.3.1-19 to show agreement between the LRA and the GALL Report with respect to the identified aging effects and mechanisms for the material and environment combination (the alignment was not intended to suggest consistency with the AMP recommended by the GALL Report), and (2) the recommended GALL Report programs are not applicable for aging management of the penetration sleeves. The applicant also stated that the penetration sleeves are installed in concrete walls, and the majority of the sleeve is located within the wall, while a small portion may protrude past the wall surface and into a soil environment. Most of the sleeve is protected on both the outer and inner surface by concrete, grout, or elastomer seal material. The applicant further stated that potential degradation of the small portion of the steel sleeve that protrudes past the exterior wall surface and is subject to the groundwater or soil environment will not impact the intended function given that most of the sleeve is protected on both the inner and outer surface and thus degradation of this area of the sleeve is unlikely to penetrate to a wall depth sufficient to impact the intended function. The applicant stated that the Structures Monitoring Program includes inspections of the penetration seals and the associated sleeves on a 5 year interval. These inspections will detect material degradation or indications of seal leakage prior to loss of intended function.

The staff reviewed the applicant’s response and noted that the penetration sleeves are structural components embedded in concrete and that the buried portion is not reasonably accessible for inspection. Visual inspections from the inside of the wall, on a 5 year frequency, will be able to detect degradation prior to a loss of intended function. Based on its review, the staff finds the applicant’s aging management approach acceptable because the Structures Monitoring Program includes appropriate inspections to detect degradation of the penetration sleeves prior to a loss of intended function. The staff’s concern in RAI 3.5.2.1-1 is resolved.

The staff finds the use of the Structures Monitoring Program acceptable for managing the aging effects associated with these penetration sleeves for the reasons as stated in the staff’s evaluation of the applicant’s response to RAI 3.5.2.1-1.

Based on the program identified, the staff concludes that the applicant’s program meets SRP-LR Section 3.3.2.2.8 criteria. For those items that apply to LRA Section 3.3.2.2.8, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

The staff reviewed LRA Section 3.3.2.2.9 against the criteria in SRP-LR Section 3.3.2.2.9.

(1) LRA Section 3.3.2.2.9.1 is associated with Table 3.3.1, item 3.3.1-20 and addresses steel piping, piping components, piping elements, and tanks exposed to fuel oil in the fire protection and standby diesel generators and auxiliary systems which are being managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling by the Fuel Oil Chemistry and One-Time Inspection Programs. The applicant addressed the further evaluation requirements by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Fuel Oil Chemistry Program.

The staff reviewed LRA Section 3.3.2.2.9.1 against the criteria in SRP-LR Section 3.3.2.2.9, item 1, which states that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling could occur for steel piping, piping components, piping elements, and tanks exposed to fuel oil. The SRP-LR also states that the existing AMP relies on the fuel oil chemistry program for monitoring and control of fuel oil contamination to manage loss of material due to corrosion or fouling. Corrosion or fouling may occur at locations where contaminants accumulate. The effectiveness of the fuel oil chemistry control should be verified to ensure that corrosion does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring or progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's Fuel Oil Chemistry and One-Time Inspection Programs and its evaluations are documented in SER Sections 3.0.3.2.10 and 3.0.3.1.11, respectively. The applicant stated that the One-Time Inspection Program includes: (1) determination of sample size based on an assessment of materials, environment, plausible aging effects and mechanisms, and operating experience; (2) identification of inspection locations based on the aging effect; (3) selection of the examination technique with acceptance criteria; and (4) evaluation of the results including the need for additional inspections or other corrective actions. The staff finds the applicant's proposal to manage aging for these components acceptable because: (1) the Fuel Oil Chemistry Program will assure that contaminants are maintained at acceptable levels in fuel oil and identify the actions required if the fuel oil contaminants exceed limits, and (2) the One-Time Inspection Program will include a one-time inspection of select components at susceptible locations (e.g., low or stagnant flow areas) to verify the effectiveness of the Fuel Oil Chemistry Program for managing the effects of aging due to the potential corrosion mechanisms.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.9, item 1 criteria. For those line items that apply to LRA Section 3.3.2.2.9.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.3.2.2.9.2 is associated with Table 3.3.1, item 3.3.1-21 and addresses steel heat exchanger components exposed to lubricating oil in the closed-cycle cooling water system which are being managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling by the Lubricating Oil Analysis and One-Time Inspection Programs. The applicant addressed the further evaluation requirements by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program. Lubricating oil systems are maintained to high cleanliness standards. Lubricating oil formulations include corrosion inhibitors; thus, the potential for water and contaminant intrusion is low compared to fuel oil systems, where the bulk storage, delivery, and transport of the fuel oil increase the likelihood of moisture and microorganism contamination.

The staff reviewed LRA Section 3.3.2.2.9.2 against the criteria in SRP-LR Section 3.3.2.2.9, item 2, which states that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling could occur for steel heat exchanger components exposed to lubricating oil. The SRP-LR also states that the existing program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring or progressing very slowly so that the component’s intended function will be maintained during the period of extended operation.

The staff reviewed the applicant’s Lubricating Oil Analysis and One-Time Inspection Programs and its evaluations are documented in SER Sections 3.0.3.2.13 and 3.0.3.1.11, respectively. In its review of components associated with LRA item 3.3.1-21, the staff finds the applicant’s proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection Programs acceptable because: (1) the applicant will perform sufficient inspections for each material-environment combination to provide an overall assessment of any aging degradation that may be occurring; (2) the selection of inspections will consider materials, operating environments, industry and plant-specific operating experience, engineering evaluations of equipment performance, and susceptibility to aging due to time in service, severity of operating conditions, and lowest design margins; (3) recurring surveillance and maintenance activities provide the ability to detect aging of the material-environment combination prior to loss of function; and (4) inspection results will be trended.

Based on the programs identified, the staff concludes that the applicant’s programs meet SRP-LR Section 3.3.2.2.9, item 2 criteria. For those line items that apply to LRA Section 3.3.2.2.9.2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on a review of the programs identified, the staff concludes that the applicant’s programs meet SRP-LR Section 3.3.2.2.9 criteria. For those line items that apply to LRA Section 3.3.2.2.9, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.3.2.2.10 against the criteria in SRP-LR Section 3.3.2.2.10.

(1) LRA Section 3.3.2.2.10.1 refers to Table 3.3.1, item 3.3.1-22 and addresses loss of material due to pitting and crevice corrosion. The applicant stated that this aging effect is not applicable because there is no steel piping with elastomer lining or steel piping with stainless steel cladding exposed to treated water in the auxiliary system that are within the scope of license renewal at HCGS.

SRP-LR Section 3.3.2.2.10.1 states that loss of material due to pitting and crevice corrosion could occur in BWR and PWR steel piping with elastomer lining or stainless steel cladding that are exposed to treated water and treated borated water if the cladding or lining is degraded.

The staff reviewed the applicant's UFSAR and finds that SRP-LR Section 3.3.2.2.10, item 1 is not applicable to HCGS because there is no steel piping with elastomer lining or steel piping with stainless steel cladding exposed to treated water in the auxiliary system that are within the scope of license renewal at HCGS, and the staff guidance in this SRP-LR section is only applicable to steel piping with elastomer lining or steel piping with stainless steel cladding exposed to treated water in the auxiliary system that are within the scope of license renewal.

(2) LRA Section 3.3.2.2.10, item 2 referenced by LRA Table 3.3.1, items 3.3.1-23 and 3.3.1-24 addresses stainless steel and aluminum piping, piping components, and piping elements and stainless steel heat exchanger components exposed to treated water which are being managed for loss of material due to pitting and crevice corrosion. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry and One-Time Inspection Programs will be used to manage this aging effect for related components in a variety of systems.

The staff reviewed LRA Section 3.3.2.2.10, item 2 against the criteria described in SRP-LR Section 3.3.2.2.10, item 2, which states that loss of material due to pitting and crevice corrosion could occur for stainless steel and aluminum piping, piping components, and piping elements and for stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water. The SRP-LR also states that the existing AMP relies on monitoring and controlling water chemistry to mitigate degradation and that a one-time inspection of components at susceptible locations is an acceptable method to verify the effectiveness of the water chemistry program.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection Programs is documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. In its review of components associated with items 3.3.1-23 and 3.3.1-24, the staff finds that the credited programs are acceptable because the Water Chemistry Program will ensure that contaminants are maintained below applicable limits to minimize loss of material due to pitting and crevice corrosion, and the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program by including inspections at appropriate locations, including low or stagnant flow areas.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10, item 2 criteria. For those items that apply to LRA

Section 3.3.2.2.10, item 2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(3) LRA Section 3.3.2.2.10.3 refers to LRA Table 3.3.1, item 3.3.1-25 and addresses copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external) which are being managed for loss of material due to pitting and crevice corrosion by the Periodic Inspection Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Periodic Inspection Program will be implemented to manage loss of material due to pitting and crevice corrosion of the copper alloy HVAC piping, piping components, and piping elements exposed to wetted air or gas in the control room and control area HVAC systems; filtration, recirculation, and ventilation system; remote shutdown panel room HVAC system; and standby diesel generator area ventilation system. The applicant stated that the wetted air or gas environment assumed for these components includes the potential for wetting due to condensation. The applicant further stated that the Periodic Inspection Program includes visual inspections to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions.

The staff reviewed LRA Section 3.3.2.2.10.3 against the criteria in SRP-LR Section 3.3.2.2.10, item 3, which states that loss of material due to pitting and crevice corrosion could occur for copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external). The SRP-LR also states that the staff reviews the applicant's plant-specific program to ensure that an adequate program will be in place for the management of these aging effects.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff notes that the applicant is using the Periodic Inspection Program to manage loss of material due to pitting and crevice corrosion for copper alloy HVAC piping, piping components, and piping elements exposed to condensation by conducting visual inspection of copper alloy HVAC piping, piping components, and piping elements exposed to condensation to detect pitting and crevice corrosion. In its review of components associated with item 3.3.1-25, the staff finds the applicant's proposal to manage aging using the Periodic Inspection Program acceptable because it requires visual inspection techniques which are capable of detecting loss of material due to corrosion by the presence of localized discoloration and surface irregularities, such as rust, scale, deposits, surface pitting, surface discontinuities, and coating degradation.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10, item 3 criteria. For those line items that apply to LRA Section 3.3.2.2.10.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(4) LRA Section 3.3.2.2.10.4 is associated with Table 3.3.1, item 3.3.1-26 and addresses copper alloy piping, piping components, and piping elements exposed to lubricating oil in the closed-cycle cooling water system which are being managed for loss of material due to pitting and crevice corrosion by the Lubricating Oil Analysis and One-Time Inspection Programs. The applicant addressed the further evaluation requirements by stating that

the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program.

The staff reviewed LRA Section 3.3.2.2.10.4, item 26 against the criteria in SRP-LR Section 3.3.2.2.10, item 4, which states that loss of material due to pitting and crevice corrosion, could occur for copper alloy piping, piping components, and piping elements exposed to lubricating oil. The SRP-LR also states that the existing program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring or progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's Lubricating Oil Analysis and One-Time Inspection Programs and its evaluations are documented in SER Sections 3.0.3.2.13 and 3.0.3.1.11, respectively. In its review of components associated with LRA item 3.3.1-26, the staff finds the applicant's proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection Programs acceptable because: (1) the applicant will perform sufficient inspections for each material-environment combination to provide an overall assessment of any aging degradation that may be occurring; (2) the selection of inspections will consider materials, operating environments, industry and plant-specific operating experience, engineering evaluations of equipment performance, and susceptibility to aging due to time in service, severity of operating conditions, and lowest design margins; (3) recurring surveillance and maintenance activities provide the ability to detect aging of the material-environment combination prior to loss of function; and (4) inspection results will be trended.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10, item 4 criteria. For those line items that apply to LRA Section 3.3.2.2.10.4, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(5) LRA Section 3.3.2.2.10.5 refers to LRA Table 3.3.1, item 3.3.1-27 and addresses HVAC aluminum piping, piping components, piping elements, stainless steel ducting and components, and damper housing exposed to condensation which are being managed for loss of material due to pitting and crevice corrosion by the Periodic Inspection Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Periodic Inspection Program will be implemented to manage loss of material due to pitting and crevice corrosion of the stainless steel and aluminum HVAC ducting and ducting components, damper housing, piping, piping components, and piping elements exposed to wetted air or gas in the control room and control area HVAC, fire pump house ventilation, makeup demineralizer, reactor building ventilation, remote shutdown panel room HVAC, service water intake ventilation, standby diesel generators and auxiliary, and standby diesel generator area ventilation systems. The applicant stated that the wetted air or gas environment assumed for these components includes the potential for wetting due to condensation. The applicant further stated that the Periodic Inspection Program includes visual inspections to assure that existing

environmental conditions are not causing material degradation that could result in a loss of component intended functions.

The staff reviewed LRA Section 3.3.2.2.10.5 against the criteria in SRP-LR Section 3.3.2.2.10, item 5, which states that loss of material due to pitting and crevice corrosion, could occur for HVAC aluminum piping, piping components, and piping elements and stainless steel ducting and damper housing components exposed to condensation. The SRP-LR also states that the staff reviews the applicant's plant-specific program to ensure that an adequate program will be in place for the management of these aging effects.

The staff's evaluation of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The staff notes that the applicant is using the Periodic Inspection Program to manage loss of material due to pitting and crevice corrosion for HVAC aluminum piping, piping components, and piping elements and stainless steel ducting and damper housing components exposed to condensation by conducting visual inspection of HVAC aluminum piping, piping components, and piping elements and stainless steel ducting and components exposed to condensation to detect pitting and crevice corrosion. In its review of components associated with item 3.3.1-27, the staff finds the applicant's proposal to manage aging using the Periodic Inspection Program acceptable because it requires visual inspection techniques which are capable of detecting loss of material due to corrosion by the presence of localized discoloration and surface irregularities, such as rust, scale, deposits, surface pitting, surface discontinuities, and coating degradation.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10.5 criteria. For those line items that apply to LRA Section 3.1.2.2.10.5, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(6) LRA Section 3.3.2.2.10.6 refers to Table 3.3-1, item 3.3.1-28 and addresses copper alloy fire protection system piping, piping components, and piping elements exposed to internal condensation which are being managed for loss of material due to pitting and crevice corrosion by the Fire Protection and Fire Water System Programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Fire Protection and Fire Water System Programs include periodic system and component inspections that include inspection of the sprinkler heads and restricting orifices as part of surveillance activities. In addition, the Fire Water System Program includes 50-year sprinkler head inspections using the guidance of NFPA-25.

The staff reviewed LRA Section 3.3.2.2.10, item 6 against the criteria in SRP-LR Section 3.3.2.2.10, item 6, which states that loss of material due to pitting and crevice corrosion, could occur for copper alloy fire protection system piping, piping components, and piping elements exposed to internal condensation. The SRP-LR also states that the GALL Report recommends further evaluation of a plant-specific program to ensure that these aging effects are adequately managed.

The staff's evaluation of the applicant's Fire Protection and Fire Water System Programs are documented in SER Sections 3.0.3.2.7 and 3.0.3.2.8, respectively. In its review of components associated with item 3.3.1-28 for which the applicant cited note E, the staff noted that the applicant credited the Fire Protection Program to manage aging for copper alloy restricting orifices exposed to wetted air or gas in LRA Table 3.3.2-10. The staff also noted that the Fire Protection Program performs visual inspections of fire barriers and the external surfaces of the halon and CO_2 systems and includes performance testing of the diesel driven fire pump fuel supply lines. The staff further noted that the Fire Protection Program does not include criteria for inspections of the internal surfaces of components which could detect loss of material for the copper alloy restricting orifice listed in Table 3.3.2-10.

By letter dated June 22, 2010, the staff issued RAI 3.3.2.2.10.6-1, requesting that the applicant justify how the Fire Protection Program will adequately manage loss of material due to pitting and crevice corrosion for copper alloy restricting orifices exposed to internal condensation.

In its response dated July 19, 2010, the applicant stated that the copper alloy restricting orifices in Table 3.3.2-10: (1) are located on sprinkler systems that use fused heads in order to allow testing of system alarms, (2) are normally isolated from the system by closed test valves, and (3) do not normally contain water. The applicant also stated that the restricting orifices have no safety or pressure boundary function and are not within the scope of license renewal. As a result, the applicant revised Table 3.3.2-10 to delete the AMR results for copper alloy restricting orifices exposed externally to indoor air and internally to wetted air or gas. The staff finds the applicant's response to RAI 3.3.2.2.10.6-1 acceptable because the copper alloy restricting orifices in Table 3.3.2-10 are not within the flow path of a system credited with a safety function and do not contain water which could result in spatial interaction with a safety-related component and, therefore, are not within the scope of license renewal. The staff's concern described in RAI 3.3.2.2.10.6-1 is resolved.

In its review of components associated with item 3.3.1-28, the staff noted that the applicant credited the Fire Water System Program to manage loss of material for copper alloy sprinkler heads exposed to wetted air or gas in LRA Table 3.3.2-10. The staff also noted that in it Fire Water System Program, the applicant stated an enhancement to its Fire Water System Program to replace or perform 50-year sprinkler head inspections and testing using the guidance of NFPA-25, "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (2002 Edition), Section 5-3.1.1. The applicant also stated that these inspections will be performed by the 50-year inservice date and every 10-years thereafter. The staff finds the applicant's Fire Water System Program acceptable to manage loss of material for copper alloy sprinkler heads because the program will replace or test the sprinkler heads in accordance with industry standards, which is consistent with the GALL Report recommendations.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10, item 6 criteria. For those line items that apply to LRA Section 3.3.2.2.10, item 6, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(7) LRA Section 3.3.2.2.10.7 refers to Table 3.3.1, item 3.3.1-29 and addresses loss of material due to pitting and crevice corrosion in stainless steel piping, piping components, and piping elements exposed to soil. The applicant stated that this item is not applicable because the stainless steel components exposed to soil in the auxiliary systems are also

subject to MIC, in addition to pitting and crevice corrosion. The applicant also stated that the Buried Non-Steel Piping Inspection Program will be used to manage loss of material due to pitting, crevice, and microbiologically-influenced corrosion in stainless steel piping components and piping elements exposed to soil.

The staff reviewed LRA Section 3.3.2.2.10.7 against the criteria in SRP-LR Section 3.3.2.2.10.7, which states that loss of material due to pitting and crevice corrosion could occur in stainless steel piping, piping components, and piping elements in a soil environment. The GALL Report recommends further evaluation of a plant-specific program to ensure that the aging effect is adequately managed. The acceptance criteria for the further evaluation of the plant-specific AMP are described in Branch Technical Position RSLB-1.

The staff reviewed the LRA and identified in AMR items in Tables 3.3.2-10 and 3.4.2-1 that the applicant will use the Buried Non-Steel Piping Inspection Program to manage the loss of material due to pitting, crevice, and microbiologically-influenced corrosion for the stainless steel piping and fittings exposed to soil. The AMR items cite generic note H indicating that the aging effect is not included in the GALL Report for this component, material, and environment combination. The staff further reviewed the applicant's Buried Non-Steel Piping Inspection Program, which is evaluated in SER Section 3.0.3.3.4. The staff finds that the credited program is acceptable because the Buried Non-Steel Piping Inspection Program requires periodic visual inspections of the external surfaces of components when exposed to ensure that the loss of material aging effect will be adequately managed. The staff finds the applicant's management for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion acceptable because the applicant satisfied the acceptance criteria in SRP-LR Section 3.3.2.2.10.7.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.10.7 criteria. For those items that apply to LRA Section 3.3.2.2.10.7, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(8) LRA Section 3.3.2.2.10.8 is associated with Table 3.3.1, item 3.3.1-30 and addresses stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution which are being managed for loss of material due to pitting and crevice corrosion by the Water Chemistry and One-Time Inspection Programs. The applicant addressed the further evaluation requirements by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Water Chemistry Program.

The staff reviewed LRA Section 3.3.2.2.10.8, item 30 against the criteria in SRP-LR Section 3.3.2.2.10, item 8, which states that loss of material due to pitting and crevice corrosion could occur in stainless steel piping, piping components, and piping elements of the BWR standby liquid control system exposed to sodium pentaborate solution. The SRP-LR also states that the existing program relies on monitoring and control of water chemistry to manage the aging effects of loss of material due to pitting and crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause loss of material due to pitting and crevice corrosion. Therefore, the GALL Report recommends that the effectiveness of the water chemistry control program should be verified to ensure corrosion does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring or progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's Water Chemistry and One-Time Inspection Programs and its evaluations are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. In its review of components associated with LRA item 3.3.1-30, the staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection Programs acceptable because the Water Chemistry Program will ensure that contaminants are maintained below applicable limits to minimize loss of material due to pitting and crevice corrosion, and the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program by including inspections at appropriate locations, including low or stagnant flow areas.

Based on the Programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10, item 8 criteria. For those line items that apply to LRA Section 3.3.2.2.10.8, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10 criteria. For those line items that apply to LRA Section 3.3.2.2.10, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.11 Loss of Material Due to Pitting, Crevice, and Galvanic Corrosion

LRA Section 3.3.2.2.11 refers to Table 3.3.1, item 3.3.1-31 and addresses copper alloy piping, piping components, and piping elements exposed to treated water which are being managed for loss of material due to pitting, crevice, and galvanic corrosion by the Water Chemistry and One-Time Inspection Programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that monitoring and controlling water chemistry in accordance with specified guidelines prevent or mitigate loss of material aging effects in applicable components exposed to treated water in the HPCI and RCIC systems. The applicant also stated that the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program.

The staff reviewed LRA Section 3.3.2.2.11 against the criteria described in SRP-LR Section 3.3.2.2.11, which states that loss of material due to pitting, crevice, and galvanic corrosion could occur for copper alloy piping, piping components, and piping elements exposed to treated water. The SRP-LR also states that the existing AMP relies on monitoring and controlling water chemistry to mitigate degradation and that a one-time inspection of select components at susceptible locations is an acceptable method to verify the effectiveness of the water chemistry program.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection Programs is documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. In its review of components associated with item 3.3.1-31, the staff finds the applicant's proposal to manage aging using the above programs acceptable because the Water Chemistry Program will ensure that contaminants are maintained below applicable limits to minimize loss of material due to pitting, crevice, and galvanic corrosion, and the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program by including inspections at appropriate locations, including low or stagnant flow areas.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.11 criteria. For those items that apply to LRA Section 3.3.2.2.11, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.12 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion

The staff reviewed LRA Section 3.3.2.2.12 against the criteria in SRP-LR Section 3.3.2.2.12.

(1) LRA Section 3.3.2.2.12.1 is associated with Table 3.3.1, item 3.3.1-32 and addresses stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to fuel oil in the fire protection system and the standby diesel generators and auxiliary systems which are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Fuel Oil Chemistry and One-Time Inspection Programs. The applicant addressed the further evaluation requirements by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Fuel Oil Chemistry Program.

The applicant stated that for item 3.3.1-32, the applicability does not include aluminum piping, piping components, and piping elements exposed to fuel oil. The staff reviewed the LRA AMR items associated with Table 3.3.1, item 3.3.1-32 and confirmed that there are no aluminum piping, piping components, and piping elements exposed to fuel oil in the auxiliary systems.

The staff reviewed LRA Section 3.3.2.2.12.1 against the criteria in SRP-LR Section 3.3.2.2.12, item 1, which states that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling could occur for steel piping, piping components, piping elements, and tanks exposed to fuel oil. The SRP-LR also states that the existing AMP relies on the fuel oil chemistry program for monitoring and control of fuel oil contamination to manage loss of material due to corrosion or fouling. Corrosion or fouling may occur at locations where contaminants accumulate. The effectiveness of the fuel oil chemistry control should be verified to ensure that corrosion does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring or progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's Fuel Oil Chemistry and the One-Time Inspection Programs and its evaluations are documented in SER Sections 3.0.3.2.10 and 3.0.3.1.11, respectively. The applicant stated that the One-Time Inspection Program includes: (1) determination of sample size based on an assessment of materials, environment, plausible aging effects and mechanisms, and operating experience; (2) identification of inspection locations based on the aging effect; (3) selection of the examination technique with acceptance criteria; and (4) evaluation of the results including the need for additional inspections or other corrective actions. The staff finds the applicant's proposal to manage aging for these components acceptable because: (1) the Fuel Oil Chemistry Program will assure that contaminants are maintained at acceptable levels in fuel oil and identify the actions required if the fuel oil contaminants exceed limits, and (2) the One-Time Inspection Program will include a one-time inspection of select components at susceptible locations (e.g., low or stagnant flow areas) to verify the effectiveness of the Fuel Oil Chemistry Program for managing the effects of aging due to the potential corrosion mechanisms.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.12, item 1 criteria. For those line items that apply to LRA Section 3.3.2.2.12.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.3.2.2.12.2 is associated with Table 3.3.1, item 3.3.1-33 and addresses stainless steel piping, piping components, and piping elements exposed to lubricating oil for the standby diesel generators and auxiliary systems which are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Lubricating Oil Analysis and One-Time Inspection Programs. The applicant addressed the further evaluation requirements by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program. The applicant also stated that loss of material due to MIC is not applicable for stainless steel in a lubricating oil environment, and industry and plant-specific operating experience indicates that the potential for significant degradation of lubricating oil systems due to MIC is minimal. Lubricating oil systems are maintained to high cleanliness standards by design, lubricating oil formulations include corrosion inhibitors, and the potential for water and contaminant intrusion is low compared to fuel oil systems, where the bulk storage, delivery, and transport of the fuel oil increases the likelihood of moisture and microorganism contamination.

The staff reviewed LRA Section 3.3.2.2.12.2 against the criteria in SRP-LR Section 3.3.2.2.12, item 2, which states that loss of material due to pitting, crevice, and microbiologically-influenced corrosion could occur for stainless steel piping, piping components, and piping elements exposed to lubricating oil. The SRP-LR also states that the existing AMP relies on the lubricating oil analysis program for monitoring and control of lubricating oil contamination to manage loss of material due to corrosion. Corrosion or fouling may occur at locations where contaminants accumulate. The effectiveness of the lubricating oil chemistry control should be verified to ensure that corrosion does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring or progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's Lubricating Oil Chemistry and One-Time Inspection Programs and its evaluations are documented in SER Sections 3.0.3.2.13 and 3.0.3.1.11, respectively. In its review of components associated with LRA item 3.3.1-33, the staff finds the applicant's proposal to manage aging using the Lubricating Oil Chemistry and One-Time Inspection Programs acceptable because: (1) the applicant will perform sufficient inspections for each material-environment combination to provide an overall assessment of any aging degradation that may be occurring; (2) the selection of inspections will consider materials, operating environments, industry and plant-specific operating experience, engineering evaluations of equipment performance, and susceptibility to aging due to time in service, severity of operating conditions, and lowest design margins; (3) recurring surveillance and maintenance activities provide the ability to detect aging of the material-environment combination prior to loss of function; and (4) inspection results will be trended.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.12, item 2 criteria. For those line items that apply to LRA Section 3.3.2.2.12.2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on a review of the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.12 criteria. For those line items that apply to LRA Section 3.3.2.2.12, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.13 Loss of Material Due to Wear

LRA Section 3.3.2.2.13 refers to Table 3.3.1, item 3.3.1-34 and addresses elastomer components that are exposed to air – indoor uncontrolled (internal or external) and that may experience loss of material due to wear. The applicant stated that elastomer components determined to be subject to wear based on plant operating experience are periodically replaced and are not subject to an AMR. The applicant also stated that elastomer components that are not periodically replaced are evaluated for hardening and loss of strength due to elastomer degradation under Table 3.3.1, item 3.3.1-11 and are managed by the plant-specific Periodic Inspection Program. The applicant further stated that elastomeric fire barrier components are evaluated for increased hardness, shrinkage, and loss of strength due to weathering under Table 3.3.1, item 3.3.1-61 and are managed by the Fire Protection Program.

The staff reviewed LRA Section 3.3.2.2.13 against the criteria in SRP-LR Section 3.3.2.2.13, which states that loss of material due to wear could occur in elastomer seals and components exposed to air – indoor uncontrolled (internal or external). The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

By letter dated June 3, 2010, the staff issued RAI 3.3.2.2.13-01 requesting that the applicant: (1) identify what systems contain in-scope elastomer components that experience wear and are subject to periodic replacement, (2) clarify whether the replacement frequency for elastomer components is based on a qualified life or a specified time period, (3) provide the technical basis for the component's qualified life or replacement time period, and (4) justify that the replacement frequency is adequate to ensure that failure due to age-related wear does not occur between successive replacements.

In its response dated June 30, 2010, the applicant stated that in-scope elastomer components that experience wear and are subject to periodic replacement are the inflatable elastomer seals in the fuel pool gates and fire hoses. The inflatable elastomer gate seals are subject to relative motion between two surfaces during gate installation and removal activities and are, therefore, potentially subject to wear or mechanical damage to the elastomer surfaces. Fire hoses are subject to relative motion when installed on hose reels or hose racks, or when deployed for use or testing. The applicant also stated that the fuel pool gate elastomer seals were periodically replaced on a 54-month basis; however, a recent change allows inspections to dictate the need for replacement but not to exceed a 10-year replacement frequency. The applicant further stated that as per LRA Section 2.1.6.4, fire hoses are considered to be a consumable item whose replacement frequency is based on NFPA testing standards that are implemented by controlled station procedures.

The staff notes that although the replacement frequency for the fire hoses are based on testing, this testing is controlled by plant procedures and it is a well known fact that fire hoses are replaced based on this testing or inspection by users. The staff finds the applicant's response acceptable because the in-scope elastomer seals that are subject to wear are appropriately evaluated as not being long-lived passive items and thus are screened out from aging management. The staff's concern described in RAI 3.3.2.2.13-01 is resolved.

Based upon the applicant's periodic replacement of elastomer components subject to wear, the staff finds that an AMR of these components is not required and finds it acceptable for the applicant to designate AMR results in Table 3.3.1, item 3.3.1-34 as not applicable.

3.3.2.2.14 Loss of Material Due to Cladding Breach

LRA Section 3.3.2.2.14 refers to Table 3.3.1, item 3.3.1-35 and addresses loss of material due to cladding breach. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.3.2.2.14 states that loss of material due to cladding breach could occur for PWR steel charging pump casings with stainless steel cladding exposed to treated borated water. SRP-LR Table 3.3-1 identifies item 35 applicable to PWRs.

The staff verified that SRP-LR Section 3.3.2.2.14 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWR steel with stainless steel cladding pump casing exposed to treated borated water.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.3.2.2.14 do not apply to HCGS because the guidance is applicable to PWRs.

3.3.2.2.15 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA program.

3.3.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.3.2-1 through 3.3.2-32, the staff reviewed additional details of AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.3.2-1 through 3.3.2-32, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information concerning how the aging effects will be managed. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the aging effects will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.3.2.3.1 Auxiliary Systems – Chilled Water System – Summary of Aging Management Evaluation – LRA Table 3.3.2-1

The staff reviewed LRA Table 3.3.2-1, which summarizes the results of AMR evaluations for the chilled water system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.2 Auxiliary Systems – Closed-Cycle Cooling Water System – Summary of Aging Management Evaluation – LRA Table 3.3.2-2

The staff reviewed LRA Table 3.3.2-2, which summarizes the results of AMR evaluations for the closed-cycle cooling water system component groups.

In LRA Table 3.3.2-2, the applicant stated that copper alloy heat exchanger components exposed to wetted air and gas are being managed for reduction of heat transfer due to fouling by the Periodic Inspection Program. The AMR line items cite generic note H, which indicates that the aging effect is not addressed in the GALL Report for this component, material, and environment combination.

The staff reviewed the applicant's Periodic Inspection Program and its evaluation is documented in SER Section 3.0.3.3.2. The staff finds the monitoring program acceptable to manage aging for these components because it includes periodic visual inspections which can detect reduction of heat transfer due to fouling and is a technique that is consistent with the GALL Report for managing this aging effect.

In LRA Table 3.3.2-2, the applicant stated that the copper alloy thermo-siphon heat exchanger components exposed to raw water are being managed for reduction of heat transfer due to fouling and loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Periodic Inspection Program. The AMR line items cite generic note G, which indicates that the environment is not addressed in the GALL Report for this component and material. The AMR line items also cite plant-specific note 4, which indicates that the components are exposed to a glycol-based coolant used in the compressor cooling system that was considered "raw water" for the purposes of the AMR review and is not monitored by the water chemistry program.

The staff reviewed the applicant's Periodic Inspection Program and its evaluation is documented in SER Section 3.0.3.3.2. The staff reviewed the GALL Report and noted that item VII.C1-6 recommends that copper alloy heat exchanger tubes exposed to raw water be managed for reduction of heat transfer by GALL AMP XI.M20, "Open-Cycle Cooling Water Program." By letter dated June 3, 2010, the staff issued RAI 3.2.2-02 requesting that the applicant justify the effectiveness of the Periodic Inspection Program in managing loss of heat transfer for these components. The staff also noted that there was a typographical error in the background of the RAI that referred to the Closed-Cycle Cooling Water Program instead of the Open-Cycle Cooling Water Program. In its response dated June 30, 2010, the applicant stated that the copper alloy heat exchanger is exposed to closed-cycle cooling water on one side that is being managed by the Closed-Cycle Cooling Water Program in another AMR line item and exposed to a glycol-based coolant on the other side which is being managed by the Periodic Inspection Program. The applicant also stated that the Periodic Inspection Program is adequate to manage aging for the copper alloy heat exchanger surfaces exposed to the glycol-based coolant because the program includes visual inspections of heat transfer surfaces which can detect fouling, and any degradation of the surfaces will be entered into the corrective action program. The staff finds the applicant's response to RAI 3.2.2-02 and its proposal to manage aging for these components using the Periodic Inspection Program acceptable because the applicant's Periodic Inspection Program includes visual inspections which can detect reduction of heat transfer due to fouling and loss of material due to pitting, crevice, and microbiologically-influenced corrosion in a glycol-based environment, and the use of visual inspections is a technique that is consistent with the GALL Report for managing these aging effects.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-2, the applicant stated that aluminum sensor elements internally exposed to closed-cycle cooling water are being managed for loss of material due to pitting and crevice corrosion by the Closed-Cycle Cooling Water Program. The AMR line item cites generic note G for this item indicating that the environment is not addressed in the GALL Report for this component and material.

The staff reviewed the associated line item in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because, as noted in the GALL Report, aluminum is susceptible to loss of material due to pitting and crevice corrosion in treated water environments, which include the closed-cycle cooling water system. The staff's evaluation of the applicant's Closed-Cycle Cooling Water System Program is documented in SER Section 3.0.3.2.5 and notes that the program includes corrosion inhibitors and water purity to mitigate corrosion. The staff finds the applicant's proposal to manage aging using the Closed-Cycle Cooling Water System Program acceptable because this program manages loss of material by controlling closed-cycle cooling water chemistry to minimize corrosion by conducting visual and NDEs and by implementing a one-time inspection to verify the effectiveness of the program.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.3 Auxiliary Systems – Compressed Air System – Summary of Aging Management Evaluation – LRA Table 3.3.2-3

The staff reviewed LRA Table 3.3.2-3, which summarizes the results of AMR evaluations for the compressed air system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.4 Auxiliary Systems – Containment Inerting and Purging System – Summary of Aging Management Evaluation – LRA Table 3.3.2-4

The staff reviewed LRA Table 3.3.2-4, which summarizes the results of AMR evaluations for the containment inerting and purging system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.5 Auxiliary Systems – Control Area Chilled Water Systems – Summary of Aging Management Evaluation – LRA Table 3.3.2-5

The staff reviewed LRA Table 3.3.2-5, which summarizes the results of AMR evaluations for the control area chilled water system component groups.

In LRA Table 3.3.2-5, the applicant stated that for glass exposed to closed-cycle cooling water, there is no aging effect and no AMP is proposed. The AMR line items cite generic note G, indicating that this environment is not in the GALL Report for this component and material.

The staff finds the applicant's proposal acceptable because there are no known aging effects for glass exposed to any water environment of nuclear power plants, and this approach is consistent with the GALL Report which states that there are no AERMs for glass exposed to treated, raw, and treated borated water (GALL AMR items VII.J-11, VII J-12, and VII J-13, respectively).

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-5, the applicant stated that copper alloy heat exchanger components exposed to wetted air and gas are being managed for reduction of heat transfer due to fouling by the Periodic Inspection Program. The AMR line items cite generic note G, which indicates that the environment is not addressed in the GALL Report for this component and material.

The staff reviewed the applicant's Periodic Inspection Program and its evaluation is documented in SER Section 3.0.3.3.2. The staff finds the monitoring program acceptable to manage aging for these components because it includes visual inspections which can detect reduction of heat transfer due to fouling and is a technique that is consistent with the GALL Report for managing the aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.6 Auxiliary Systems – Control Rod Drive System – Summary of Aging Management Evaluation – LRA Table 3.3.2-6

The staff reviewed LRA Table 3.3.2-6, which summarizes the results of AMR evaluations for the CRD system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.7 Auxiliary Systems – Control Room and Control Area Heating, Ventilation, and Air Conditioning Systems – Summary of Aging Management Evaluation – LRA Table 3.3.2-7

The staff reviewed LRA Table 3.3.2-7, which summarizes the results of AMR evaluations for the control room and control area HVAC system component groups.

In LRA Table 3.3.2-7, the applicant stated that polymer ducting and components exposed to air–indoor (external), or air or gas–wetted (internal) have no AERM and that for this component, material, and environment combination, no AMP is needed. The AMR line items cite generic note F, indicating that the material is not in the GALL Report for this component. The staff reviewed all material entries in the GALL Report and confirmed that polymer material is not included in the GALL Report.

For these AMR results, the applicant also cited plant-specific note 3, stating that:

> The polymer (plexiglass) material located indoors and subject to an air-indoor or air-gas (wetted) environment is not subject to significant aging effects. Polymer materials do not experience aging effects unless exposed to temperatures, radiation or chemicals capable of attacking the specific polymer chemical composition. Polymer materials are selected for compatibility with the environment during the design, and if properly selected will not experience significant degradation. Polymer (plexiglass) material in this non-aggressive air environment is not expected to experience significant aging effects. This is consistent with plant operating experience.

Based on its review of technical literature (e.g., Roff, W.J., *Fibres, Plastics, and Rubbers: A Handbook of Common Polymers*, Academic Press Inc., New York, 1956) and current industry research and operating experience related to plexiglass and related polymers, the staff has determined that, in the absence of specific environmental stressors such as ultraviolet light, high radiation, or ozone concentrations, components made of these materials do not exhibit aging effects of concern during the period of extended operation. The staff has determined that for plexiglass and related polymer components in a plant indoor air, or air or gas – wetted environment, there are no aging effects that cause degradation of the components during the period of extended operation. On the basis that the subject components have no aging effects that cause degradation during the period of extended operation, the staff finds the applicant's AMR results for these components, indicating that there is no AERM and no AMP is needed, to be acceptable.

3.3.2.3.8 Auxiliary Systems – Cranes and Hoists – Summary of Aging Management Evaluation – LRA Table 3.3.2-8

In LRA Table 3.3.2-8, the applicant stated that carbon steel cranes or hoists exposed to outdoor air are being managed for cumulative fatigue damage using a TLAA. The AMR line item cites generic note G, indicating that the environment is not in the GALL Report for this component and material.

The staff evaluated the applicant's claim that the cumulative fatigue damage of the carbon steel crane would be adequately managed by the TLAA. The TLAA, which is evaluated in SER Section 4.7, includes the review of existing 40-year design bases to determine the number of load cycles considered in the design for each of the cranes within the scope of license renewal and then the development of a 60-year projection for load cycles for each crane. The staff finds that the applicant's management of the carbon steel crane and hoist exposed to outdoor air acceptable because the process followed for fatigue damage is consistent with the recommendation in the GALL Report for other similar environments.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-8, the applicant stated that carbon steel cranes or hoists (rail system) exposed to external outdoor air are being managed for loss of material due to wear by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

Program. The AMR line items cite generic note G, which indicates that the environment is not addressed in the GALL Report for this component and material.

The staff reviewed the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program and its evaluation is documented in SER Section 3.0.3.2.6. The staff finds the monitoring program acceptable to manage aging for these components because it includes visual inspections of rails in the rail system which are appropriate to detect loss of material due to wear. Also, the AMP is implemented through station procedures that are based on ASME/ANSI B30.2, B30.10, B30.11, and B30.16 and rely upon visual inspection to manage loss of material in an indoor air and outdoor air environment.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.9 Auxiliary Systems – Equipment and Floor Drainage System – Summary of Aging Management Evaluation – LRA Table 3.3.2-9

The staff reviewed LRA Table 3.3.2-9, which summarizes the results of AMR evaluations for the equipment and floor drainage system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.10 Auxiliary Systems – Fire Protection System – Summary of Aging Management Evaluation – LRA Table 3.3.2-10

The staff reviewed LRA Table 3.3.2-10, which summarizes the results of AMRs for the fire protection system component groups.

In LRA Table 3.3.2-10, the applicant stated that copper alloy piping, fittings, valves, and hose components exposed externally to outdoor air are being managed for loss of material due to pitting and crevice corrosion by the Fire Protection Program. The AMR line items cite generic note G, which indicates that the environment is not addressed in the GALL Report for this component and material.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.7. The staff finds the monitoring program acceptable to manage aging for these components because it includes visual inspections of component external surfaces and functional testing which are appropriate to detect loss of material for these components.

In its RAI response to RAI 2.3.3.10-2 dated April 6, 2010, the applicant stated that it discovered that the flexible metal hose components were inadvertently identified with an outdoor air environment but the hoses are located indoors. The applicant revised Table 3.3.2-10 component type hoses to refer the AMR line item with Table 3.2.1, item 3.2.1-53 and cite generic note A, which indicates that the component, material, environment, and aging effect is consistent with the GALL Report.

The staff notes that the applicant, during its review of RAI 2.3.3.10-2, identified the following error in its LRA: Table 3.3.2-10 showed the environment for flexible metal hoses as “Air – Outdoor” and as a result, these hoses were within the scope of license renewal and subject to an AMR. The applicant revised Table 3.3.2-10 to show the environment for these hoses as “Air–Indoor” and, therefore, these hoses are consistent with the GALL Report for this AMR line item. The staff concurs with this correction.

In its response to RAI 2.3.3.10-2 dated April 6, 2010, the applicant stated that fire retardant coatings for structural steel are within the scope of license renewal and subject to an AMR. The applicant revised Tables 2.3.3-10 and 3.3.2-10 to add fire retardant coatings for structural steel as a fire barrier that is within the scope of license renewal and subject to an AMR and added Note 19 to Table 3.3.2-10. Note 19 states, “based on industry standards and guidelines, cementitious fireproofing is susceptible to loss of material due to cracking in this environment. This aging effect will be monitored and managed with the fire protection program.” This note justifies the inclusion of fire retardant coating for structural steel in the Fire Protection Program. The AMR line items cite generic note F, which indicates that the material is not addressed in the GALL Report for this component.

The staff’s evaluation of the applicant’s Fire Protection Program is documented in SER Section 3.0.3.2.7. The staff noted that the applicant’s Fire Protection Program includes visual inspections of fire barriers at least once every 18 months for detection of cracking and loss of material and that these inspections are appropriate to detect cracking and loss of material for cementitious fire proofing. The staff finds the applicant’s currently proposed programs acceptable to manage cracking and loss of material for cementitious fire proofing fire barriers because the periodic visual inspections performed by the Fire Protection Program will confirm that there is no loss of material or cracking, or it will result in a corrective action to assess the situation.

In its response to RAI 2.3.3.10-4 dated April 6, 2010, the applicant stated that the steel wall panels and windows are within the scope of license renewal and are subject to an AMR. A review of LRA Table 3.3.2-10 determined that the steel fire barrier materials were inadvertently omitted from this table. Table 3.3.2-10 was revised to add these materials to the existing fire barrier (walls, ceilings, and floors) component types which are exposed to an indoor air environment and are being managed for loss of material due to corrosion by the Fire Protection Program. The AMR line items cite generic note F, which indicates that the material is not addressed in the GALL Report for this component.

The staff reviewed the applicant’s Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.7. The staff noted that the applicant’s Fire Protection Program includes visual inspections of fire barriers at least once every 18 months for detection of loss of material and that these inspections are appropriate to detect loss of material for carbon steel. The staff finds the applicant’s currently proposed programs acceptable to manage loss of material for carbon steel fire barriers because the periodic visual inspections performed by the Fire Protection Program will confirm that there is no loss of material, or it will result in a corrective action to assess the situation.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL

Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-10, the applicant stated that copper alloy sprinkler heads and valve body components exposed externally to outdoor air are being managed for loss of material due to pitting and crevice corrosion by the Fire Water System Program. The AMR line items cite generic note G, which indicates that the environment is not addressed in the GALL Report for this component and material.

The staff reviewed the applicant's Fire Water System Program and its evaluation is documented in SER Section 3.0.3.2.8. The staff finds the monitoring program acceptable to manage aging for these components because it includes visual inspections of fire protection system components (including sprinkler head inspections per NFPA-25), volumetric testing, and performance testing (e.g., system functional tests, flow tests, and flushes) which can detect loss of material.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Tables 3.3.2-10 and 3.3.2-27, the applicant stated that carbon or low alloy steel bolting externally exposed to soil is being managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and loss of preload due to thermal effects, gasket creep, and self-loosening by the Bolting Integrity Program. The AMR line items cite generic note G, indicating that the environment is not in the GALL Report for this component and material. The applicant also stated that it plans to conduct external inspections in accordance with the frequency outlined in the Buried Piping Inspection Program or the Buried Non-Steel Piping Inspection Program.

The staff's evaluation of the Bolting Integrity and Buried Piping Inspection Programs are documented in SER Sections 3.0.3.2.4 and 3.0.3.2.12, respectively. The staff noted that the Bolting Integrity Program manages loss of material by performing visual inspections for bolted joint leakage. The staff also noted that the frequency established for the inspections performed by the Buried Piping Inspection and Buried Non-Steel Piping Inspection Programs are based on preventive measures, including application of external coatings and wrappings. It was unclear to the staff if external coatings and wrappings are used on the carbon and low alloy steel bolting listed in LRA Tables 3.3.2-10 and 3.3.2-27. By letter dated June 1, 2010, the staff issued RAI 3.3.2.3.10-01 requesting that the applicant provide additional information regarding whether the carbon and low alloy steel bolting exposed to soil is wrapped or coated, and if the components are not wrapped or coated, provide additional information regarding why the frequency adopted from the Buried Piping Inspection Program or the Buried Non-Steel Piping Inspection Program is applicable.

In its response dated June 24, 2010, the applicant stated that station documentation and site interviews indicate that buried bolting was initially coated, but that buried carbon steel bolts in the fire protection system have been observed without coatings and that it does not take credit for coatings to prevent loss of intended function. The applicant also stated that buried bolting in the service water system is designated as Class 3 and is inspected in accordance with ASME Code Section XI IWD-2500 and IWD-5000, 1998 Edition with 2000 Addenda, which allows use of a flow test to confirm no significant leakage in lieu of visual inspections. The applicant further stated that non-ASME buried bolts will be opportunistically inspected in accordance with the Buried Piping Inspection Program. The staff notes that ASME Code Section IX, Subsection IWA-5244, “Buried Components,” indicates that for buried components where a VT-2 visual examination cannot be performed, the examination requirement is satisfied by conducting a pressure loss test or a flow test. The staff finds the applicant’s response to RAI 3.3.2.3.10-01 and its proposal to manage aging for bolting exposed to soil using the Bolting Integrity and Buried Piping Inspection Programs acceptable because the buried bolts will be inspected using either system flow tests or opportunistic inspections, which is consistent with the GALL Report recommendations that periodic inspections be conducted. The staff’s concern described in RAI 3.3.2.3.10-01 is resolved.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Tables 3.3.2-10 and 3.4.2-1, the applicant stated that stainless steel piping and fittings exposed externally to soil are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Buried Non-Steel Piping Inspection Program. The AMR line items cite generic note H, which indicates that the aging effect is not addressed in the GALL Report for this component, material, and environment combination.

The staff reviewed the applicant’s Buried Non-Steel Piping Inspection Program and its evaluation is documented in SER Section 3.0.3.3.4. The staff finds the applicant’s proposed program acceptable to manage aging for these components because it uses opportunistic and focused visual inspections of coatings and the base metal to detect loss of material due to pitting, crevice, and microbiologically-influenced corrosion.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3)

In LRA Table 3.3.2-10, the applicant stated that grout fire barriers (penetration seals) exposed to indoor and outdoor air have an aging effect of cracking due to shrinkage, and in an outdoor air environment, have an aging effect of loss of material due to spalling and scaling and cracking due to freeze-thaw. The applicant also stated that these aging effects will be managed by both the Fire Protection and Structures Monitoring Programs. The AMR line items cite generic note F, indicating that the material is not addressed in the GALL Report for this component. The AMR line items also cite plant-specific note 8, indicating that grout is susceptible to cracking due to shrinkage in this environment, based on industry standards and guidelines. The AMR line items further cite plant-specific note 9, indicating that grout is susceptible to loss of material due to spalling and scaling and cracking due to freeze-thaw in an air – outdoor environment. The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because grout is similar to concrete, which experiences these same aging effects.

The staff's evaluation of the applicant's Fire Protection and Structures Monitoring Programs is documented in SER Sections 3.0.3.2.7 and 3.0.3.2.16, respectively. The staff noted that the Fire Protection Program is used for other fire barriers, such as penetration seals, walls, floors, and ceilings, and that the grout material in this case is used as a penetration seal fire barrier. The staff also noted that the applicant's Fire Protection Program includes visual inspections of fire barriers at least once every 18 months for detection of cracking and loss of material and that these inspections are appropriate to detect cracking and loss of material for grout. The staff further noted that the applicant's Structures Monitoring Program also includes periodic visual inspections of structural concrete for cracking and loss of material at a frequency not to exceed 5 years and that these inspections are also appropriate for detecting aging of grout. The staff finds the applicant's currently proposed programs acceptable to manage cracking and loss of material for grout fire barriers because the periodic visual inspections performed by the Fire Protection and the Structures Monitoring Programs will confirm that there is no loss of material or cracking, or it will result in a corrective action to assess the situation.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-10, the applicant stated that alumina silicate fire barriers (wraps) exposed to indoor air are being managed for change in material properties and cracking by the Fire Protection Program. The AMR line items cite generic note F, indicating that the material is not addressed in the GALL Report for this component. The AMR line items also cite plant-specific note 11, indicating that the Fire Protection Program will be used to manage these aging effects.

The staff reviewed the associated line items in the LRA and noted that the LRA did not include a description of the change in material properties that will be managed by the program or the parameters that will be observed during the visual inspections of the aluminum silicate fire barriers (wraps). It is not clear to the staff how the visual examination would detect change in material properties of the aluminum silicate fire wrap.

By letter dated June 22, 2010, the staff issued RAI 3.3.2.3.10-02 requesting that the applicant describe the material properties of the aluminum silicate fire barrier wraps that will be managed by the Fire Protection Program, the parameters that will be observed during the visual inspection of the aluminum silicate fire barrier wraps, and the acceptance criteria used to evaluate the change in material properties. The staff also requested that the applicant justify how the visual inspections used by the Fire Protection Program will manage the aging effect of change in material properties.

In its response dated July 19, 2010, the applicant stated that change in material properties for fire barrier wraps include degradation due to physical damage that may occur during plant activities and could challenge the design thickness of the fire wrap. The applicant also stated that the inspection parameters include physical damage, gaps in the outer layer of the mat, hole in the foil, loose bands, sagging, or falling mesh wire cloth. The applicant further stated that the fire wrap is considered acceptable if its observed condition is the same as its designed condition. The staff finds the applicant's response to RAI 3.3.2.3.10-02 acceptable because the inspection parameters and acceptance criteria for fire barrier wraps are consistent with industry guidance.

The staff's evaluation of the applicant's Fire Protection Program is documented in SER Section 3.0.3.2.7. The staff noted that NUREG-1924, "Electrical Raceway Fire Barrier Systems in US Plants" (May 2010), states that aluminum silicate is commonly used as a fire resistant fiber in flexible fire barrier blankets and wraps. The staff also noted that the applicant's Fire Protection Program includes visual inspections of fire barriers once every 18 months to detect cracking and loss of material and that these inspections are appropriate to detect aging for fire barrier blankets and wraps. The staff finds the Fire Protection Program acceptable to manage aging for these fire barriers because the visual inspections are capable of detecting cracking and change in material properties prior to loss of intended function.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-10, the applicant stated that polymer hoses exposed externally to indoor air and internally to wetted air or gas have no AERMs. The AMR line items cite generic note F, indicating that the material is not addressed in the GALL Report for this component. The AMR line items also cite plant-specific note 18, which states:

> The polymer (plexiglass) material located indoors and subject to an indoor air or air-gas (wetted) environment is not subject to significant aging effects. Polymer materials do not experience aging effects unless exposed to temperatures, radiation or chemicals capable of attacking the specific polymer chemical composition. Polymer materials are selected for compatibility with the environment during the design, and if properly selected will not experience significant degradation. Polymer (teflon) material in this non-aggressive air environment is not expected to experience significant aging effects. This is consistent with plant operating experience.

Based on industry experience, the staff noted that Teflon is susceptible to radiation, which could cause an aging effect of change in material properties. It is not clear to the staff where the polymer hoses listed in LRA Table 3.3.2-10 are located such that the environment is considered non-aggressive.

By letter dated June 22, 2010, the staff issued RAI 3.3.2.3.10-03 requesting that the applicant explain the bounding environmental conditions used to determine that the environment is non-aggressive and the selection criteria used for the polymer hoses within the scope of license renewal.

In its response dated July 19, 2010, the applicant stated that the polymer hoses exposed to indoor air or wetted air or gas in Table 3.3.2-10 includes two Teflon hoses with quick disconnects that connect the halon cylinders to the control room operator's console and are normally disconnected and stored on a hose rack in the main control room. The applicant also stated that the internal environment the hoses are exposed to is halon gas but was classified as wetted air or gas to account for moisture infiltration. The Teflon hoses were chosen because they are chemically resistant to common solvents, acids, and bases; are chemically inert; and are rated for temperatures up to 500 °F. The applicant further stated that the environment in the main control room is non-aggressive because it is climate controlled and a low radiation area. The staff finds the applicant's response to RAI 3.3.2.3.10-03 acceptable because the hose material selected is appropriate for use in the halon system, the main control room environment is non-aggressive, and Teflon hoses in this non-aggressive environment would not be expected to experience AERMs.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.11 Auxiliary Systems – Fire Pump House Ventilation System – Summary of Aging Management Evaluation – LRA Table 3.3.2-11

The staff reviewed LRA Table 3.3.2-11, which summarizes the results of AMR evaluations for the fire pump house ventilation system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.12 Auxiliary Systems – Fresh Water Supply System – Summary of Aging Management Evaluation – LRA Table 3.3.2-12

The staff reviewed LRA Table 3.3.2-12, which summarizes the results of AMR evaluations for the fresh water supply system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.13 Auxiliary Systems – Fuel Handling and Storage System – Summary of Aging Management Evaluation – LRA Table 3.3.2-13

The staff reviewed LRA Table 3.3.2-13, which summarizes the results of AMR evaluations for the fuel handling and storage system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.14 Auxiliary Systems – Fuel Pool Cooling and Cleanup System – Summary of Aging Management Evaluation – LRA Table 3.3.2-14

The staff reviewed LRA Table 3.3.2-14, which summarizes the results of AMRs for the fuel pool cooling and cleanup system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.15 Auxiliary Systems – Hardened Torus Vent System – Summary of Aging Management Evaluation – LRA Table 3.3.2-15

The staff reviewed LRA Table 3.3.2-15, which summarizes the results of AMR evaluations for the hardened torus vent system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.16 Auxiliary Systems – Hydrogen Water Chemistry System – Summary of Aging Management Evaluation – LRA Table 3.3.2-16

The staff reviewed LRA Table 3.3.2-16, which summarizes the results of AMR evaluations for the hydrogen water chemistry system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.17 Auxiliary Systems – Leak Detection and Radiation Monitoring System – Summary of Aging Management Evaluation – LRA Table 3.3.2-17

The staff reviewed LRA Table 3.3.2-17, which summarizes the results of AMR evaluations for the leak detection and radiation monitoring system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.18 Auxiliary Systems – Makeup Demineralizer System – Summary of Aging Management Evaluation – LRA Table 3.3.2-18

The staff reviewed LRA Table 3.3.2-18, which summarizes the results of AMRs for the makeup demineralizer system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.19 Auxiliary Systems – Primary Containment Instrument Gas System – Summary of Aging Management Evaluation – LRA Table 3.3.2-19

The staff reviewed LRA Table 3.3.2-19, which summarizes the results of AMR evaluations for the primary containment instrument gas system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.20 Auxiliary Systems – Primary Containment Leakage Rate Testing System – Summary of Aging Management Evaluation – LRA Table 3.3.2-20

The staff reviewed LRA Table 3.3.2-20, which summarizes the results of AMR evaluations for the primary containment leakage rate testing system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.21 Auxiliary Systems – Process and Post-Accident Sampling Systems – Summary of Aging Management Evaluation – LRA Table 3.3.2-21

The staff reviewed LRA Table 3.3.2-21, which summarizes the results of AMR evaluations for the process and post-accident sampling systems component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.22 Auxiliary Systems – Radwaste System – Summary of Aging Management Evaluation – LRA Table 3.3.2-22

The staff reviewed LRA Table 3.3.2-22, which summarizes the results of AMR evaluations for the radwaste system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.23 Auxiliary Systems – Reactor Building Ventilation System – Summary of Aging Management Evaluation – LRA Table 3.3.2-23

The staff reviewed LRA Table 3.3.2-23, which summarizes the results of AMR evaluations for the reactor building ventilation system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.24 Auxiliary Systems – Reactor Water Cleanup System – Summary of Aging Management Evaluation – LRA Table 3.3.2-24

The staff reviewed LRA Table 3.3.2-24, which summarizes the results of AMR evaluations for the RWCU system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.25 Auxiliary Systems – Remote Shutdown Panel Room Heating, Ventilation, and Air Conditioning System – Summary of Aging Management Evaluation – LRA Table 3.3.2-25

The staff reviewed LRA Table 3.3.2-25, which summarizes the results of AMR evaluations for the remote shutdown panel room HVAC system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.26 Auxiliary Systems – Service Water Intake Ventilation System – Summary of Aging Management Evaluation – LRA Table 3.3.2-26

The staff reviewed LRA Table 3.3.2-26, which summarizes the results of AMR evaluations for the service water intake ventilation system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.27 Auxiliary Systems – Service Water System – Summary of Aging Management Evaluation – LRA Table 3.3.2-27

In LRA Table 3.3.2-27, the applicant stated that the nickel-alloy bolting in the air – indoor (external) environment is being managed for loss of preload due to thermal effects, gasket creep, and self-loosening by the Bolting Integrity Program. The AMR line item cites generic note G, indicating that this environment is not in the GALL Report for this component and material. In LRA Table 3.3.2-27, the applicant stated that the nickel alloy (tube side components) in the raw water (internal) environment is being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling by the Open-Cycle Cooling Water System Program. The AMR line items cite generic note H, indicating that this aging effect is not in the GALL Report for this component, material, and environment combination.

The staff reviewed the associated line item and the Bolting Integrity Program in the LRA and confirmed that the applicant had identified the correct aging effects for this component, material, and environment combination because loss of preload may occur for bolting exposed to indoor air regardless of the fabrication material.

The staff noted that even though the loss of preload for nickel-alloy bolting exposed to air – indoor (external) is not specifically addressed in the GALL Report, proper maintenance practices require an appropriate preload to exist. Table IX.E of the GALL Report describes "loss of preload" as occurring due to gasket creep, thermal effects (including differential expansion and creep or stress relaxation), and self-loosening (which includes vibration, joint flexing, cyclic shear loads, and thermal cycles). The staff noted that the environment of air – indoor (external) could involve differential thermal expansion issues with dissimilar materials that are often found in the bolted joint configuration; therefore, the aging effect of concern is loss of preload.

The staff noted that the evidence for loss of preload of the nickel-alloy bolting in air – indoor (external) is similar to that described for steel bolting in GALL AMR item VII.I-5 where loss of preload in steel bolting for the auxiliary systems is managed by GALL AMP XI.M18, "Bolting Integrity." The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.4. The staff noted that the Bolting Integrity Program provides for condition monitoring of pressure retaining bolting by performing visual inspections which are capable of detecting gross loosening of the bolts or leakage that is indicative of loss of preload. The staff also noted that the program includes procurement controls and installation practices defined in plant procedures to ensure that only approved lubricants, sealants, and proper torques are applied to bolting which are capable of preventing loss of preload. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because it includes plant procedures that ensure proper torques are applied to bolting and visual inspections are performed to ensure that leakage and gross loosening of bolts do not occur.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-27, the applicant stated that the nickel alloy (tube side components) in the raw water (internal) environment is being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling by the Open-Cycle Cooling Water System Program. The AMR line items cite generic note H, indicating that this aging effect is not in the GALL Report for this component, material, and environment combination.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environmental combination because loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling may occur for any corrosion resistant alloy that is exposed to raw water (water containing contamination like bacterial microbes).

The staff noted that even though loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling for nickel alloy (tube side components) exposed to raw water (internal) is not specifically addressed in the GALL Report, proper maintenance practices require the plant to manage the internal corrosion of heat exchanger components to minimize susceptibility of corrosion and to verify that corrosion has not exceeded acceptable limits. The staff noted that as described in the Metals Handbook Volume 13, 9th Edition, by the American Society for Metals, nickel is a corrosion resistant material and nickel-alloy heat exchanger components used in heat exchanger tubes internally exposed to raw water may experience loss of material.

The staff further noted that evidence of loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling of the nickel-alloy (tube side) components in raw water (internal) is similar to that described for copper alloy in GALL AMR item VII.C1-9 where loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling in copper alloy for the open-cycle cooling water system (service water system) is managed by the Open-Cycle Cooling Water System Program, consistent with the recommendations of the GALL Report.

The staff's review of the Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.1.9. The staff noted that the applicant's program provides instructions and controls for mitigating degradation through raw water chemistry control (sodium hypochlorite injection), performance-monitoring through station testing, and condition monitoring through inspection and testing of the service water system. The staff noted that the methods described in the program and the frequencies for inspections under the existing program have been effective in detecting the applicable aging effects and preventing significant degradation. The staff finds the applicant's proposal to manage aging using the Open-Cycle Cooling Water

System Program acceptable because it includes raw water chemistry control (sodium hypochlorite injection) to mitigate corrosion and also includes performance-monitoring through station testing and condition monitoring through inspection and testing which are capable of determining if loss of material has occurred.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-27, the applicant stated that the carbon or low alloy steel with nickel-alloy cladding (tube side components) in the raw water (internal) environment is being managed for loss of material due to pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling by the Open-Cycle Cooling Water System Program. The AMR line items cite generic note H, indicating that this aging effect is not in the GALL Report for this component, material, and environment combination.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because loss of material due to pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling may occur for any corrosion resistant alloy that is exposed to raw water (water containing contamination like bacterial microbes).

The staff noted that even though loss of material due to pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling for carbon or low alloy steel with nickel-alloy cladding (tube side components) exposed to raw water (internal) is not specifically addressed in the GALL Report, proper maintenance practices require the plant to manage the internal corrosion of heat exchanger components to minimize susceptibility of corrosion and to verify that corrosion has not exceeded acceptable limits. The staff noted that as described in the Metals Handbook Volume 13, 9th Edition, by the American Society for Metals, nickel is a corrosion resistant material and nickel-clad heat exchanger components used in heat exchanger tubes internally exposed to raw water may experience loss of material.

The staff further noted that evidence of loss of material due to pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling of the carbon or low alloy steel with nickel-alloy cladding (tube side components) in raw water (internal) is similar to that described for copper alloy in GALL AMR item VII.C1-3 where loss of material due to pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling in copper alloy for the open-cycle cooling water system (service water system) is managed by the Open-Cycle Cooling Water System Program, consistent with the recommendations of the GALL Report.

The staff’s review of the Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.1.9. The staff noted that the applicant’s program provides instructions and controls for mitigating degradation through raw water chemistry control (sodium hypochlorite injection), performance-monitoring through station testing, and condition monitoring through inspection and testing of the service water system. The staff noted that the methods described in the program and the frequencies for inspections under the existing program have been effective in detecting the applicable aging effects and preventing significant degradation. The staff finds the applicant’s proposal to manage aging using the Open-Cycle Cooling Water System Program acceptable because it includes raw water chemistry control (sodium hypochlorite injection) to mitigate corrosion and also includes performance-monitoring through station testing and condition monitoring through inspection and testing which are capable of determining if loss of material has occurred.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-27, the applicant stated that aluminum bronze bolting (with 8 percent aluminum or more) exposed to indoor air, outdoor air, and raw water are being managed for loss of preload due to thermal effects, gasket creep, and self-loosening and loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Bolting Integrity Program. The AMR line items cite generic note F, indicating that the material is not addressed in the GALL Report for this component. In addition, line items associated with mechanical closure bolting exposed to raw water cite plant-specific note 1, which states that inspection activities for bolting in a submerged environment are performed in conjunction with associated component maintenance activities.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because, as noted in the GALL Report, copper alloys including aluminum bronze are susceptible to loss of material due to pitting and crevice corrosion. The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.4. The staff notes that the applicant's program incorporates NRC and industry recommendations and performs examinations in accordance with the ASME Code Section XI ISI program plan as part of a corporate component pressure retaining bolting program. The staff also notes that the inspection of submerged components by the Bolting Integrity Program has been addressed in RAI B.2.1.12-02 in SER Section 3.0.3.2.4. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the program manages cracking, loss of material, and loss of preload by performing visual inspections for pressure retaining bolted joint leakage in indoor and outdoor air and in raw and treated water.

In LRA Table 3.3.2-27, the applicant stated that aluminum bronze bolting, pump casings, and valve bodies (with 8 percent aluminum or more) exposed to raw water are being managed for loss of material due to selective leaching by the Selective Leaching of Materials Program. The AMR line items cited generic note F for the bolting, indicating that the material is not addressed in the GALL Report for this component, and generic note H for the pump casings and valve bodies, indicating that the aging effect is not addressed in the GALL Report for this component, material, and environment combination.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because, as noted in the LRA, industry operating experience has identified that aluminum bronze is susceptible to selective leaching and HCGS has identified de-alloying of aluminum bronze valves in raw water environments. The staff's evaluation of the applicant's Selective Leaching of Materials Program is documented in SER Section 3.0.3.1.12. The staff finds the applicant's proposal to manage aging using the Selective Leaching of Materials Program acceptable because it uses visual inspections, which have already identified this aging effect at HCGS, and hardness testing.

In LRA Table 3.3.2-27, the applicant stated that aluminum bronze pump casings (with 8 percent aluminum or more) exposed to outdoor air (external) are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Open-Cycle Cooling Water Program. The AMR line items cite generic note G, indicating that the environment is not in the GALL Report for this component and material.

The staff reviewed the associated line item in the LRA and questioned the use of the Open-Cycle Cooling Water Program for managing the loss of material for the external surface of the aluminum pump casing because the LRA describes the program as managing internal corrosion. By letter dated June 3, 2010, the staff issued RAI 3.2.2-1 requesting that the applicant justify the appropriateness for using the Open-Cycle Cooling Water Program to manage the aging concerns of the external pump casing exposed to outdoor air.

In its response dated June 30, 2010, the applicant stated that the areas of the aluminum bronze pump casings that are exposed to the outdoor air environment are inaccessible during normal operation and cannot be observed during regular system walkdowns because they are below the floor level in the service water intake structure and subject to river water tidal variations. The applicant further stated that the Open-Cycle Cooling Water System Program includes periodic maintenance activities, as part of the GL 89-13 program, for managing loss of material, including removal and refurbishment of these pumps every 10 years. This activity includes a visual inspection of the external surfaces of the pump casing. The applicant also stated that the Open-Cycle Cooling Water Program includes condition monitoring activities that are able to detect the loss of material, and any corrosion, in excess of minor surface corrosion, will be entered into the corrective action program and evaluated further by engineering staff members.

The staff finds the applicant’s response to the RAI and its proposal to manage aging using the above program acceptable because the Open-Cycle Cooling Water Program has specific preventive maintenance activities for the pump casing, which uses periodic visual inspections capable of identifying the loss of material for aluminum bronze components. The staff’s concern described in RAI 3.2.2-1 is resolved.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-27, the applicant indicated that the reduction of heat transfer due to fouling for titanium heat exchanger components exposed to closed-cycle cooling water (external) is not addressed by the GALL Report. The applicant referenced note F for this item indicating that the material is not in the GALL Report for this component. The applicant further indicated that the aging issue is managed by the Closed-Cycle Cooling Water System Program.

The staff confirmed that the GALL Report does not include an AERM or AMP for titanium alloy heat exchanger components exposed to a closed-cycle cooling water environment.

The staff further reviewed the applicant’s Closed-Cycle Cooling Water System Program evaluated in SER Section 3.0.3.2.5. The staff finds the monitoring program acceptable because it includes performance monitoring, visual inspections, and NDEs to determine component functionality for reduction of heat transfer due to fouling. The performance monitoring, visual inspections, and NDEs are consistent with the GALL Report and thus the monitoring program will adequately manage the aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-27, the applicant indicated that the reduction of heat transfer due to fouling and loss of material due to fouling for titanium heat exchanger components exposed to raw water (internal) is not addressed by the GALL Report. The applicant referenced note F for this item, indicating that the material is not in the GALL Report for this component. The applicant further indicated that the aging issue is managed by the Open-Cycle Cooling Water System Program.

The staff confirmed that the GALL Report does not include an AERM or AMP for titanium alloy heat exchanger components exposed to raw water (internal) environments.

The staff further reviewed the applicant's Open-Cycle Cooling Water System Program evaluated in SER Section 3.0.3.1.9. The staff finds that the monitoring program is acceptable because it includes system testing, periodic inspections, and NDEs to determine component function due to reduction of heat transfer due to fouling. The program includes surveillance and control techniques to manage the aging effect. The system testing, visual inspections, and NDEs are consistent with the GALL Report and thus the monitoring program adequately manages the aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-27, the applicant indicated that the titanium heat exchanger components exposed to closed-cycle cooling water (external) is not addressed by the GALL Report. The applicant referenced note F for this item indicating that the material is not in the GALL Report for this component. The applicant further indicated that no AMP is needed for this component, material, and environment combination when the intended function is a pressure boundary. In plant-specific note 10, the applicant stated that titanium material is corrosion resistant in water up to 260 °C (500 °F) due to a protective oxide film. The applicant indicated that this was consistent with plant operating experience.

The staff confirmed that the GALL Report does not include an AERM or AMP for titanium alloy heat exchanger components exposed to closed-cycle cooling water (external) environments.

The staff notes that based on multiple references (e.g., AZo Journal of Materials Online (http://www.azom.com), Britannica Encyclopedia, Key to Metals Database (online) Article 24), titanium is resistant to pitting, general, and crevice corrosion and SCC in salt water and turbine exhaust steam environments in essence due to its formation of very stable, continuous, highly adherent, and protective oxide films on metal surfaces. Based on these references, the staff also notes that due to its corrosion resistance capabilities, it is widely used in the refinery industry for condenser tubing and the aerospace industry in temperature applications up to 600 °C. The staff finds the applicant's proposal that there are no AERMs or AMPs for titanium alloy heat exchanger components exposed to closed-cycle cooling water (external) environment whose intended function is a pressure boundary acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.3.2-27, the applicant stated that carbon or low alloy steel with nickel-alloy cladding strainer bodies exposed internally to raw water are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling by the Open-Cycle Cooling Water System Program. The AMR line items cite generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination.

The staff's evaluation of the applicant's Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.1.9. The staff noted that the applicant's Open-Cycle Cooling Water System Program manages loss of material and fouling by controlling raw water chemistry, system and component performance testing, and either visual inspections or NDEs. The staff finds the applicant's proposed program to manage carbon or low alloy steel with nickel-alloy cladding strainer bodies for loss of material and fouling acceptable because the performance testing, visual inspections, and NDEs used by the program are appropriate for detection of these aging effects and its water chemistry control activities will minimize fouling.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff's evaluation for carbon or low alloy steel bolting externally exposed to soil which is being managed for loss of material or loss of preload by the Bolting Integrity Program is documented in SER Section 3.3.2.3.10.

For the component type piping and fittings, the applicant proposed to assign reinforced concrete to the Open-Cycle Cooling Water System Program to manage the aging effects of cracking, loss of bond, loss of material (spalling, scaling)/corrosion of embedded steel, increase in porosity and permeability, and aggressive chemical attack in a raw water (internal) groundwater/soil environment. This item references Note J and plant-specific note 7. Plant-specific note 7 states that, "The Open-Cycle Cooling Water System aging management program activities are adequate for managing the aging effects of the internal surfaces of reinforced concrete service water piping. The Buried Non-Steel Piping Inspection aging management program activities are adequate for managing the aging effects of the external surfaces of reinforced concrete service water piping." The applicant stated that these components have the intended function of pressure boundary and are examined using the Open-Cycle Cooling Water System Program. The staff's review of the Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.1.9. Since the Open-Cycle Cooling Water System Program includes mitigative, performance-monitoring, and condition monitoring activities to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the open-cycle cooling water system, it is unclear to the staff that this is an adequate approach to managing aging of reinforced concrete piping and fitting components subjected to a raw water (internal) environment. By letter dated June 7, 2010, the staff issued RAI 3.5.2.1-6 requesting that the applicant discuss how the Open-Cycle Cooling Water System Program will adequately address the AERMs. A further discussion of the RAI response, as well as the adequacy of the credited program to manage the aging effects, is included in SER Section 3.5.2.1.8.

3.3.2.3.28 Auxiliary Systems – Standby Diesel Generator Area Ventilation Systems – Summary of Aging Management Evaluation – LRA Table 3.3.2-28

The staff reviewed LRA Table 3.3.2-28, which summarizes the results of AMR evaluations for the standby diesel generator area ventilation system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.29 Auxiliary Systems – Standby Diesel Generators and Auxiliary Systems – Summary of Aging Management Evaluation – LRA Table 3.3.2-29

In LRA Table 3.3.2-29, the applicant stated that copper alloy (greater than 15 percent Zn) bolting components exposed to indoor air are being managed for loss of preload due to thermal effects, gasket creep, and self-loosening by the Bolting Integrity Program. The AMR line items cite generic note F, which indicates that the material is not addressed in the GALL Report for these components.

The staff reviewed the applicant's Bolting Integrity Program and its evaluation is documented in SER Section 3.0.3.2.4. The staff finds the monitoring program acceptable to manage aging for these components because it includes visual inspections during maintenance or routine observations, such as system walkdowns, which can detect loss of preload and has incorporated industry guidance on proper selection of bolting materials, lubricants, and installation torque to ensure loss of preload does not occur.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.30 Auxiliary Systems – Standby Liquid Control System – Summary of Aging Management Evaluation – LRA Table 3.3.2-30

The staff reviewed LRA Table 3.3.2-30, which summarizes the results of AMR evaluations for the standby liquid control system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.31 Auxiliary Systems – Torus Water Cleanup System – Summary of Aging Management Evaluation – LRA Table 3.3.2-31

The staff reviewed LRA Table 3.3.2-31, which summarizes the results of AMR evaluations for the torus water cleanup system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.32 Auxiliary Systems – Traversing Incore Probe System – Summary of Aging Management Evaluation – LRA Table 3.3.2-32

The staff reviewed LRA Table 3.3.2-32, which summarizes the results of AMR evaluations for the traversing incore probe system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.3.2.1.

3.3.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the auxiliary system components within the scope of license renewal and 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, as required by 10 CFR 54.21(a)(3).

3.4 <u>Aging Management of Steam and Power Conversion Systems</u>

This section of the SER documents the staff's review of the applicant's AMR results for the steam and power conversion system components and component groups of the following:

- condensate storage and transfer system
- feedwater system
- main condenser
- main steam system

3.4.1 Summary of Technical Information in the Application

LRA Section 3.4 provides AMR results for the steam and power conversion system components and component groups. In LRA Table 3.4.1, "Summary of Aging Management Evaluations for Steam and Power Conversion," the applicant provided a summary comparison of its AMRs to those evaluated in the GALL Report for steam and power conversion system components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included issue reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.4.2 Staff Evaluation

The staff reviewed LRA Section 3.4 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for steam and power conversion system components within the scope of license renewal and 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, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit of AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to verify the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.4.2.1 and 3.4.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.4.2.3.

For components which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.4-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.4 and addressed in the GALL Report.

Table 3.4-1 Staff Evaluation for Steam and Power Conversion System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to steam or treated water (3.4.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (See SER Section 3.4.2.2.1)
Steel piping, piping components, and piping elements exposed to steam (3.4.1-2)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.4.2.2.2)
Steel heat exchanger components exposed to treated water (3.4.1-3)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to BWRs (See SER Section 3.4.2.2.2)
Steel piping, piping components, and piping elements exposed to treated water (3.4.1-4)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.4.2.2.2)
Steel heat exchanger components exposed to treated water (3.4.1-5)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.4.2.2.9)
Steel and stainless steel tanks exposed to treated water (3.4.1-6)	Loss of material due to general (steel only), pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.4.2.2.7)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to lubricating oil (3.4.1-7)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.4.2.2.2)
Steel piping, piping components, and piping elements exposed to raw water (3.4.1-8)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling	Plant-specific	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.4.2.2.3)
Stainless steel and copper alloy heat exchanger tubes exposed to treated water (3.4.1-9)	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.4.2.2.4)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil (3.4.1-10)	Reduction of heat transfer due to fouling	Lubricating Oil Analysis and One-Time Inspection	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.4.2.2.4)
Buried steel piping, piping components, piping elements, and tanks (with or without coating or wrapping) exposed to soil (3.4.1-11)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	No Yes	 Buried Piping Inspection	 Consistent with GALL Report (See SER Section 3.4.2.2.5)
Steel heat exchanger components exposed to lubricating oil (3.4.1-12)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.4.2.2.5)
Stainless steel piping, piping components, and piping elements exposed to steam (3.4.1-13)	Cracking due to SCC	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.4.2.2.6)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water > 60 °C (140 °F) (3.4.1-14)	Cracking due to SCC	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.4.2.2.6)
Aluminum and copper alloy piping, piping components, and piping elements exposed to treated water (3.4.1-15)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.4.2.2.7)
Stainless steel piping, piping components, and piping elements; tanks and heat exchanger components exposed to treated water (3.4.1-16)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (See SER Section 3.4.2.2.7)
Stainless steel piping, piping components, and piping elements exposed to soil (3.4.1-17)	Loss of material due to pitting and crevice corrosion	Plant-specific	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.4.2.2.7)
Copper alloy piping, piping components, and piping elements exposed to lubricating oil (3.4.1-18)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.4.2.2.7)
Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil (3.4.1-19)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.4.2.2.8)
Steel tanks exposed to air – outdoor (external) (3.4.1-20)	Loss of material due to general, pitting, and crevice corrosion	Aboveground Steel Tanks	No	Not applicable	Not applicable to HCGS (See SER Section 3.4.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High-strength steel closure bolting exposed to air with steam or water leakage (3.4.1-21)	Cracking due to cyclic loading and SCC	Bolting Integrity	No	Not applicable	Not applicable to HCGS (See SER Section 3.4.2.1.1)
Steel bolting and closure bolting exposed to air with steam or water leakage, air – outdoor (external), or air – indoor uncontrolled (external) (3.4.1-22)	Loss of material due to general, pitting, and crevice corrosion; loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity	Consistent with GALL Report
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water > 60 °C (140 °F) (3.4.1-23)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Steel heat exchanger components exposed to closed-cycle cooling water (3.4.1-24)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water (3.4.1-25)	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water (3.4.1-26)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to closed-cycle cooling water (3.4.1-27)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel external surfaces exposed to air – indoor uncontrolled (external), condensation (external), or air – outdoor (external) (3.4.1-28)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with GALL Report
Steel piping, piping components, and piping elements exposed to steam or treated water (3.4.1-29)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Flow-Accelerated Corrosion	Consistent with GALL Report
Steel piping, piping components, and piping elements exposed to air – outdoor (internal) or condensation (internal) (3.4.1-30)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (See SER Section 3.4.2.1.3)
Steel heat exchanger components exposed to raw water (3.4.1-31)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water (3.4.1-32)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS
Stainless steel heat exchanger components exposed to raw water (3.4.1-33)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System Periodic Inspection	Consistent with GALL Report (See SER Section 3.4.2.1.2)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to raw water (3.4.1-34)	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to HCGS

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy > 15% Zn piping, piping components, and piping elements exposed to closed-cycle cooling water, raw water, or treated water (3.4.1-35)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to HCGS
Gray cast iron piping, piping components, and piping elements exposed to soil, treated water, or raw water (3.4.1-36)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to HCGS
Steel, stainless steel, and nickel-alloy piping, piping components, and piping elements exposed to steam (3.4.1-37)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Water Chemistry	Consistent with GALL Report
Steel bolting and external surfaces exposed to air with borated water leakage (3.4.1-38)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Not applicable	Not applicable to BWRs
Stainless steel piping, piping components, and piping elements exposed to steam (3.4.1-39)	Cracking due to SCC	Water Chemistry	No	Not applicable	Not applicable to BWRs
Glass piping elements exposed to air, lubricating oil, raw water, and treated water (3.4.1-40)	None	None	No	Not applicable	Not applicable to HCGS (See SER Section 3.4.2.1.1)
Stainless steel, copper alloy, and nickel-alloy piping, piping components, and piping elements exposed to air – indoor uncontrolled (external) (3.4.1-41)	None	None	No	None	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to air – indoor controlled (external) (3.4.1-42)	None	None	No	Not applicable	Not applicable to HCGS
Steel and stainless steel piping, piping components, and piping elements in concrete (3.4.1-43)	None	None	No	Not applicable	Not applicable to HCGS
Steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas (3.4.1-44)	None	None	No	Not applicable	Not applicable to HCGS

The staff's review of the steam and power conversion system component groups followed several approaches. One approach, documented in SER Section 3.4.2.1, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.4.2.2, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.4.2.3, discusses the staff's review of AMR results for components the applicant indicated are not consistent with or not addressed in the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the steam and power conversion system components is documented in SER Section 3.0.3.

3.4.2.1 AMR Results That Are Consistent with the GALL Report

LRA Section 3.4.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the steam and power conversion system components:

- Aboveground Non-Steel Tanks
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- Buried Non-Steel Piping Inspection
- Buried Piping Inspection
- External Surfaces Monitoring
- Flow-Accelerated Corrosion
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- One-Time Inspection
- Periodic Inspection

- Small-Bore Class 1 Piping Inspection
- TLAA
- Water Chemistry

LRA Tables 3.4.2-1 through 3.4.2-4 summarize the AMRs for the steam and power conversion system components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant had claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and confirmed that it had reviewed and accepted the identified exceptions to the GALL Report AMPs. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report and determined whether the AMR line item of the different component applied to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and confirmed whether the AMR line item of the different component was applicable to the component under review. The staff confirmed whether it had reviewed and accepted the exceptions to the GALL Report AMPs. It also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report and determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

The staff notes that in LRA Table 3.4.2-1 there are AMR line items for a stainless steel tank exposed to treated water. The staff also notes that the LRA does not have a line item for the tank material exposed to an air or wetted gas internal environment as would occur when the tank is partially full. The staff further notes that the LRA line items manage the aging of the tank internals using the Water Chemistry and One-Time Inspection programs. The staff finds the existing line items acceptable because the chemistry program will minimize contaminant concentrations and thus mitigate loss of material due to various corrosion mechanisms for tank internal surfaces at the fluid to air transition zone. The One-Time Inspection Program will provide reasonable assurance that an aging effect is not occurring or that the aging effect is occurring slowly enough as to not affect a component's intended function.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.1.1 Aging Management Review Results Identified as Not Applicable

LRA Table 3.4.1, item 3.4.1-20 addresses loss of material due to general, pitting, and crevice corrosion in steel tanks exposed to air – outdoor. The applicant stated that this line item is not applicable because there are no steel tanks exposed to air – outdoor (external) in the steam and power conversion system. The staff reviewed LRA Sections 2.3.4 and 3.4 and confirmed that the applicant's LRA does not have any AMR results for the steam and power conversion system that include steel tanks exposed to air – outdoor (external). The staff also reviewed the applicant's UFSAR supplement and confirmed that no in-scope steel tanks exposed to air – outdoor are present in the steam and power conversion system and, therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.4.1, item 3.4.1-21 addresses high-strength steel closure bolting exposed to air with steam or water leakage in the steam and power conversion system. The GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," to manage cracking due to cyclic loading or SCC for this component group. The applicant stated that this item is not applicable because there is no high-strength closure bolting in the steam and power conversion system. The staff reviewed LRA Sections 2.3.4 and 3.4 and confirmed that the applicant's LRA does not have any AMR results for the steam and power conversion system that includes high-strength steel closure bolting exposed to air with steam or water leakage. The staff reviewed the applicant's UFSAR supplement and confirmed that no in-scope high-strength steel closure bolting exposed to air with steam or water leakage is present in the steam and power conversion system and, therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.4.1, item 3.4.1-40 addresses glass piping elements exposed to air, lubricating oil, raw water, and treated water. The applicant stated that this line item is not applicable because there are no glass piping elements exposed to air, lubricating oil, raw water, or treated water in the steam and power conversion system. The staff reviewed LRA Sections 2.3.4 and 3.4 and confirmed that the applicant's LRA does not have any AMR results for the steam and power conversion system that include glass piping elements exposed to air, lubricating oil, raw water, and treated water. The staff notes that the applicant stated that there is no AERM or recommended AMP for this material and component combination. The staff also notes that the GALL Report recommends that there is no AERM or AMP for this material and environment combination. The staff, therefore, finds that the applicant's proposal that there is no AERM or AMP acceptable, regardless of whether or not the material and environment combination exists in the steam and power conversion system.

3.4.2.1.2 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

LRA Table 3.4.1, item 3.4.1-33 addresses stainless steel heat exchanger components exposed to raw water which are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion and fouling. The LRA credits the Periodic Inspection Program to manage aging for piping and fittings in the fresh water supply system. The GALL Report recommends GALL AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The AMR line item cites generic note E, which indicates that the line item is consistent with the GALL Report for the material, environment, and aging effect, but a different AMP is credited.

GALL AMP XI.M20 recommends preventive measures including proper selection of materials and coatings, periodic flushes and cleaning, and raw water chemistry control, as well as visual inspections and NDE testing for components exposed to open-cycle cooling water. Open-cycle cooling water is water that transfers heat from safety-related components to the ultimate heat sink.

The staff reviewed the applicant's Periodic Inspection Program and its evaluation is documented in SER Section 3.0.3.3.2. The staff noted that the Periodic Inspection Program includes periodic visual inspections of components and ultrasonic wall thickness measurements to detect loss of material and fouling. The staff also notes that the fresh water supply system supplies potable water for the plant and does not contain safety-related components exposed to open-cycle cooling water; therefore, the use of the Open-Cycle Cooling Water Program would not be appropriate. The staff finds the applicant's use of the Periodic Inspection Program acceptable to manage aging for these components because it performs periodic visual inspections and wall thickness measurements that are appropriate to detect loss of material and fouling.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.1.3 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Table 3.4.1, item 3.4.1-30 addresses steel piping, piping components, and piping elements exposed internally to outdoor air or condensation which are being managed for loss of material due to general, pitting, and crevice corrosion. The LRA credits the One-Time Inspection Program, in addition to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, to manage these aging effects for steel piping and fittings exposed internally to wetted air or gas. The GALL Report recommends GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to ensure these aging effects are adequately managed. The AMR line item that references the One-Time Inspection Program cites generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited. The AMR line item also cites plant-specific note 7, indicating that the One-Time Inspection Program is also being used to manage loss of material for the safety relief valve discharge line where it enters the torus, based upon recent industry operating experience.

The staff reviewed the AMR results lines in the LRA and confirmed that the component for which the applicant referenced item 3.4.1-30 and cited generic note E, is also being managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program in another line. The staff reviewed the applicant's One-Time Inspection Program and its evaluation is documented in SER Section 3.0.3.1.11. The staff finds the applicant's proposed program acceptable to manage aging for these components because the One-Time Inspection Program performs visual or volumetric inspections of a sampling of components to confirm that aging is not occurring or is progressing very slowly, and the program is being implemented in addition to the GALL Report recommended program for these components.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

LRA Section 3.4.2.2 provides further evaluation of aging management, as recommended by the GALL Report for the steam and power conversion system components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling
- reduction of heat transfer due to fouling
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion
- cracking due to SCC
- loss of material due to pitting and crevice corrosion
- loss of material due to pitting, crevice, and microbiologically-influenced corrosion
- loss of material due to general, pitting, crevice, and galvanic corrosion

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations to determine whether they adequately address those issues and reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.4.2.2. The staff's review of the applicant's further evaluations follows.

3.4.2.2.1 Cumulative Fatigue Damage

LRA Section 3.4.2.2.1 addresses the applicant's AMR basis for managing cumulative fatigue damage in steam and power conversion system components that were designed and analyzed to applicable design analysis criteria in the ASME Code Section III, Articles NC-3000 or ND-3000 (as applicable to Code Class 2 or 3 components, respectively) or in the ANSI B31.1 Code, and for which implicit fatigue analyses were required. In this LRA section, the applicant stated that the evaluation of fatigue is a TLAA as defined in 10 CFR 54.3 and that the TLAAs are evaluated in accordance with the TLAA acceptance criteria in 10 CFR 54.21(c)(1). The applicant stated that the HCGS piping designed to ASME Code Section III requirements for Class 2 or 3 components or to the ANSI B31.1 design code were analyzed using an implicit fatigue analysis that assumes a reduction in the component's allowable secondary stress range if more than 7,000 full-range thermal cycles are expected over the component's design lifetime.

In LRA Table 3.4.1, the applicant stated that the AMR item 3.4.1-1 for managing cumulative fatigue damage for the feedwater, main steam, and reactor water cleanup system piping, piping components, and piping elements is consistent with the staff's AMR item recommendations in AMR item 1 of Table 4 in the GALL Report, Volume 1, Revision 1. The applicant stated that, for these AMRs, cumulative fatigue damage in the components will be managed using a TLAA and that LRA Section 4.3.4 describes and evaluates implicit fatigue analysis-based TLAAs for these components.

The staff reviewed LRA Section 3.4.2.2.1 against the criteria in SRP-LR Section 3.4.2.2.1, which states that fatigue of steam and power conversion system components is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1) and in accordance with the staff's recommended acceptance criteria and review procedures for reviewing these TLAAs in SRP-LR Section 4.3, "Metal Fatigue Analysis." The staff also reviewed LRA Section 3.4.2.2.1 and the applicant's AMR items referenced to this LRA section against the staff's AMR items for evaluating cumulative fatigue damage as given in AMR item 1 in the GALL Report, Volume 1, Table 4 and the AMR items in Section VIII of the GALL Report, Volume 2, Revision 1 that derive from this GALL Report, Volume 1 AMR item.

With regard to the applicant's metal fatigue AMR item 3.4.1-1, the staff noted that AMR item 1 in Table 4 of the GALL Report, Volume 1 and AMR items VIII.B2-5 and VIII.D2-6 in the GALL Report, Volume 2 identify that cumulative fatigue damage is an applicable aging effect for steel piping, piping components, and piping elements. The staff also noted that these GALL Report AMRs recommend that the TLAA on metal fatigue be used to manage the impact of cumulative fatigue damage in these components. The staff noted that, in conformance with this recommendation, the applicant included an applicable line item in LRA Tables 3.3.2-24, 3.4.2-2, and 3.4.2-4 for steel piping, piping components, and piping elements that received ASME Code Section III CUF or ANSI B31.1 design code analysis calculations. The staff noted that the applicant credited the TLAA analysis in LRA Section 4.3.4 with the management of cumulative fatigue damage in these components. The staff found that the applicant's AMR assessment was in conformance with the recommendations in both the SRP-LR and in AMR item 1 of the GALL Volume 1, Table 4 and AMR items VIII.B2-5 and VIII.D2-6 in the GALL Report, Volume 2. Based on this review, the staff finds the applicant's AMR analysis on cumulative fatigue damage of piping, piping components, and piping elements to be acceptable because it is in conformance with the recommendations in SRP-LR Section 3.3.2.2.1 and the GALL Report AMR items that are invoked by this SRP-LR section. The staff evaluates the TLAA analysis for the support skirt and attachment welds component in SER Section 4.3.4.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.1 criteria. For those items that apply to LRA Section 3.4.2.2.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.4.2.2.2 against the criteria in SRP-LR Section 3.4.2.2.2.

(1) LRA Section 3.4.2.2.2, item 1 refers to Table 3.4.1, items 3.4.1-2 and 3.4.1-4 and addresses steel piping, piping components, piping elements, and turbine casings exposed to treated water or steam which are being managed for loss of material due to general, pitting, and crevice corrosion. The applicant addressed the further evaluation criteria of the SRP-LR by stating that this aging mechanism of the associated components in the stated environment will be managed by the Water Chemistry and One-Time Inspection programs for the condensate storage and transfer, feedwater, and main steam systems.

The staff reviewed LRA Section 3.4.2.2.2, item 1 against the criteria described in SRP-LR Section 3.4.2.2.2, item 1, which states that loss of material due to general, pitting, and crevice corrosion could occur for steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water and in steel piping, piping components, and piping elements exposed to steam. The SRP-LR also states that the existing AMP relies on monitoring and controlling water chemistry to mitigate degradation and that a one-time inspection of components at susceptible locations is an acceptable method to verify the effectiveness of the chemistry control program.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection programs is documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. In its review of components associated with items 3.4.1-2 and 3.4.1-4, the staff finds the applicant's proposed programs acceptable because the Water Chemistry Program will ensure that contaminants are maintained below applicable limits to minimize loss of material due to general, pitting, and crevice corrosion, and the One-Time Inspection Program will inspect components in aggressive environments, such as low or stagnant flow, to verify the effectiveness of the Water Chemistry Program.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.2, item 1 criteria. For those line items that apply to LRA Section 3.4.2.2.2, item 1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Section 3.4.2.2.2.1 also refers to Table 3.4.1, item 3.4.1-3 and addresses the loss of material due to general, pitting, and crevice corrosion. The applicant stated that this aging effect is not applicable to HCGS, which is a BWR.

SRP-LR Section 3.4.2.2.2.1 states that loss of material due to general, pitting, and crevice corrosion could occur for steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water and in steel piping, piping components, and piping elements exposed to steam.

The staff verified that SRP-LR Section 3.4.2.2.2.1 is not applicable to HCGS because HCGS is a BWR and the staff guidance in this SRP-LR section is only applicable to PWRs. SRP-LR Table 3.4-1 identifies item 3 as applicable to PWRs.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.4.2.2.2.1 do not apply to HCGS because the guidance is applicable to PWRs.

(2) LRA Section 3.4.2.2.2.2 refers to Table 3.4.1, item 3.4.1-7 and addresses the loss of material due to general, pitting, and crevice corrosion. The applicant stated that this aging effect is not applicable because HCGS does not have any steel piping, piping components, or piping elements exposed to a lubricating oil environment in the steam and power conversion system.

SRP-LR Section 3.4.2.2.2.2 states that loss of material due to general, pitting, and crevice corrosion could occur for steel piping, piping components, and piping elements exposed to lubricating oil.

The staff reviewed the applicant's UFSAR supplement and finds that SRP-LR Section 3.4.2.2.2, item 2 is not applicable to HCGS because HCGS does not have any steel piping, piping components, or piping elements exposed to a lubricating oil environment in the steam and power conversion system, and the staff guidance in this SRP-LR section is only applicable to BWR steel piping, piping components, or piping elements exposed to a lubricating oil environment in the steam and power conversion system.

Based on the staff's review and evaluation of the applicant's programs, the staff concludes that the applicant's programs satisfy SRP-LR Section 3.4.2.2.2 criteria. For those line items that apply to LRA Section 3.4.2.2.2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.3 Loss of Material due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

LRA Section 3.4.2.2.3 refers to Table 3.4.1, item 3.4.1-8 and addresses the loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling. The applicant stated that this aging effect is not applicable because HCGS does not have any steel piping, piping components, or piping elements exposed to a raw water environment in the steam and power conversion system.

SRP-LR Section 3.4.2.2.3 states that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling could occur for steel piping, piping components, and piping elements exposed to raw water.

The staff reviewed the applicant's UFSAR supplement and finds that SRP-LR Section 3.4.2.2.3 is not applicable to HCGS because HCGS does not have any steel piping, piping components, or piping elements exposed to a raw water environment in the steam and power conversion system, and the staff guidance in this SRP-LR section is only applicable to BWR steel piping, piping components, or piping elements exposed to a raw water environment in the steam and power conversion system.

3.4.2.2.4 Reduction of Heat Transfer Due to Fouling

The staff reviewed LRA Section 3.4.2.2.4 against the criteria in SRP-LR Section 3.4.2.2.4.

(1) LRA Section 3.4.2.2.4, item 1 refers to LRA Table 3.4.1, item 3.4.1-9 and addresses stainless steel and copper alloy heat exchanger tubes exposed to treated water which are being managed for reduction of heat transfer due to fouling by the Water Chemistry and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program for copper alloy heat exchanger components in the HPCI and RCIC systems.

The staff reviewed LRA Section 3.4.2.2.4, item 1 against the criteria in SRP-LR Section 3.4.2.2.4, item 1 which states that reduction of heat transfer due to fouling could occur for stainless steel and copper alloy heat exchanger tubes exposed to treated water and that the existing AMP relies on the control of water chemistry to manage reduction of heat transfer due to fouling. The SRP-LR also states that control of water chemistry may not always have been adequate to preclude fouling and recommends that the effectiveness of the water chemistry control be verified by a one-time inspection to ensure reduction of heat transfer does not occur.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection programs is documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. In its review of components associated with item 3.4.1-9, the staff finds the applicant's proposal to manage aging using the above programs acceptable because the Water Chemistry Program provides for periodic sampling of treated water to maintain contaminants at acceptable limits to preclude loss of heat transfer due to fouling, and the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Program by including inspections of select components at appropriate locations, including low or stagnant flow areas.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.4, item 1 criteria. For those line items that apply to LRA Section 3.4.2.2.4, item 1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.4.2.2.4.2 refers to Table 3.4.1, item 3.4.1-10 and addresses reduction of heat transfer due to fouling. The applicant stated that this aging effect is not applicable because HCGS does not have any steel, stainless steel, and copper alloy heat exchanger tubes exposed to a lubricating oil environment in the steam and power conversion system.

SRP-LR Section 3.4.2.2.4.2 states that reduction of heat transfer due to fouling could occur for steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil.

The staff reviewed the applicant's UFSAR supplement and finds that SRP-LR Section 3.4.2.2.4, item 2 is not applicable to HCGS because HCGS does not have any steel, stainless steel, and copper alloy heat exchanger tubes exposed to a lubricating oil environment in the steam and power conversion system, and the staff guidance in this SRP-LR section is only applicable to BWR steel, stainless steel, and copper alloy heat exchanger tubes exposed to a lubricating oil environment in the steam and power conversion system.

Based on the staff's review and evaluation of the applicant's programs, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.4 criteria. For those line items that apply to LRA Section 3.4.2.2.4, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.5 Loss of Material due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

The staff reviewed LRA Section 3.4.2.2.5 against the criteria in SRP-LR Section 3.4.2.2.5.

(1) LRA Section 3.4.2.2.5.1 refers to Table 3.4.1, item 3.4.1-11 and addresses loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion in steel piping, piping components, and piping elements exposed to soil. The applicant stated that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion in the steel piping, piping components, and piping elements exposed to soil in the condensate storage and transfer system will be managed by the Buried Piping Inspection Program. The applicant also stated that there are no steel tanks exposed to soil in the steam and power conversion system.

The staff reviewed LRA Section 3.4.2.2.5.1 against the criteria in SRP-LR Section 3.4.2.2.5.1, which states that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion could occur in steel piping, piping components, piping elements, and tanks, with or without coating or wrapping, in a soil environment. The SRP-LR also states that the effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material is not occurring.

The staff reviewed the applicant's Buried Piping Inspection Program, which is evaluated in SER Section 3.0.3.2.12. The staff finds that the credited program is appropriate because the Buried Piping Inspection Program relies on preventive measures such as coating and wrapping to mitigate corrosion and periodic visual inspections of external surfaces to identify coating degradation and, therefore, ensures that the loss of material aging effect will be adequately managed.

The staff reviewed the LRA AMR items and information in the UFSAR supplement associated with Table 3.4.1, item 3.4.1-11 and confirmed that there are no steel tanks exposed to soil in the steam and power conversion system. Therefore, the staff finds the applicant's determination acceptable that LRA Table 3.4.1, item 3.4.1-11 is not applicable for tanks.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.4.2.2.5.1 criteria. For those items that apply to LRA Section 3.4.2.2.5.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.4.2.2.5.2 refers to Table 3.4.1, item 3.4.1-12 and addresses loss of material due to general, pitting, crevice and microbiologically-influenced corrosion. The applicant stated that this aging effect is not applicable because HCGS does not have any steel heat exchanger components exposed to a lubricating oil environment in the steam and power conversion system.

SRP-LR Section 3.4.2.2.5.2 states that loss of material due to general, pitting, crevice and microbiologically-influenced corrosion could occur in steel heat exchangers exposed to lubricating oil.

The staff reviewed the applicant's UFSAR supplement and finds that SRP-LR Section 3.4.2.2.5, item 2 is not applicable to HCGS because HCGS does not have steel heat exchanger components exposed to a lubricating oil environment in the steam and power conversion system, and the staff guidance in this SRP-LR section is only applicable to BWR steel heat exchanger components exposed to a lubricating oil environment in the steam and power conversion system.

Based on the staff's review and evaluation of the applicant's program, the staff concludes that the applicant's program meets SRP-LR Section 3.4.2.2.5 criteria. For those line items that apply to LRA Section 3.4.2.2.5, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.6 Cracking Due to Stress-Corrosion Cracking

The staff reviewed LRA Section 3.4.2.2.6 against the criteria in SRP-LR Section 3.4.2.2.6.

LRA Section 3.4.2.2.6 refers to LRA Table 3.4.1, items 3.4.1-13 and 3.4.1-14 and addresses stainless steel piping, piping components, and piping elements exposed to steam and stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water greater than 60 °C (140 °F), respectively, which are being managed for cracking due to SCC by the Water Chemistry Program and One-Time Inspection Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will implement a One-Time Inspection Program for susceptible locations to verify the effectiveness of the Water Chemistry Program to manage cracking due to SCC.

The staff reviewed LRA Section 3.4.2.2.6 against the criteria in SRP-LR 3.4.2.2.6, which states that SCC could occur in stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water greater than 60 °C (140 °F) and for stainless steel piping, piping components, and piping elements exposed to steam. The SRP-LR further states that the existing AMP relies on monitoring and control of water chemistry. However, the SRP-LR also states that high concentrations of impurities at crevices and locations with stagnant flow conditions could cause SCC. The SRP-LR further states that the GALL Report recommends that the effectiveness of the water chemistry control program should be verified to ensure that SCC does not occur. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that SCC does not occur and that the component's intended function will be maintained during the period of extended operation.

The staff's evaluation of the applicant's Water Chemistry Program and One-Time Inspection Program is documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. The staff noted the applicant's One-Time Inspection Program includes one-time inspection of more susceptible materials in potentially more aggressive environments to manage the effects of aging. In its review of components associated with items 3.4.1-13 and 3.4.1-14, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program and One-Time Inspection Program acceptable because: (1) the Water Chemistry Program monitors the plant water chemistry control parameters against the established parameter limits and, if a parameter exceeds the limit, the program performs adequate actions such that the water chemistry control continues to mitigate the aging effect; (2) the One-Time Inspection Program includes a one-time inspection of select components to verify the effectiveness of the Water Chemistry Program in a consistent manner with the recommendation in the GALL Report; and (3) the one-time inspection can ensure that significant degradation is not occurring or progressing very slowly so that the component's intended function is maintained during the period of extended operation. The staff finds that the applicant's AMR results are consistent with GALL AMR items VIII.B2-1 and VIII.E-31 and the recommendations in the SRP-LR.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.6 criteria. For those line items that apply to LRA Section 3.4.2.2.6, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.7 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.4.2.2.7 against the criteria in SRP-LR Section 3.4.2.2.7.

(1) LRA Section 3.4.2.2.7, item 1 refers to Table 3.4.1, items 3.4.1-6, 3.4.1-15, and 3.4.1-16 and addresses copper alloy heat exchanger components and stainless steel piping, piping components, piping elements, and tanks exposed to treated water which are being managed for loss of material due to pitting and crevice corrosion. The applicant stated that this aging effect for the related components in the HPCI, RCIC, condensate storage and transfer, and main steam systems will be managed by the Water Chemistry and One-Time Inspection programs.

The staff reviewed LRA Section 3.4.2.2.7, item 1 against the criteria described in SRP-LR Section 3.4.2.2.7, item 1, which states that loss of material due to pitting and crevice corrosion could occur for stainless steel, aluminum, and copper alloy piping, piping components, and piping elements and for stainless steel tanks and heat exchanger components exposed to treated water. The SRP-LR also states that the existing AMP relies on monitoring and controlling water chemistry to mitigate degradation and that a one-time inspection of select components at susceptible locations is an acceptable method to verify the effectiveness of the chemistry control program.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection programs is documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. In its review of components associated with items 3.4.1-6, 3.4.1-15, and 3.4.1-16, the staff finds the proposed programs acceptable because the Water Chemistry Program will ensure that contaminants are maintained below applicable limits to minimize loss of material due to pitting and crevice corrosion, and the One-Time Inspection Program will inspect components in more aggressive environments, such as low or stagnant flow, to verify the effectiveness of the Water Chemistry Program.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.7, item 1 criteria. For those line items that apply to LRA Section 3.4.2.2.7, item 1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.4.2.2.7.2, associated with LRA Table 3.4.1, item 3.4.1-17, addresses loss of material due to pitting and crevice corrosion in stainless steel piping, piping components, and piping elements exposed to soil. The applicant stated that this line item is not applicable because, "the AMR methodology for stainless steel piping, piping components, and piping elements exposed to soil predicts microbiologically-influenced corrosion in addition to pitting, and crevice corrosion. There are no NUREG-1801 AMR lines available for stainless steel components exposed to soil that include all of these mechanisms."

The staff reviewed LRA Tables 3.4.2-1 and notes that the applicant has included an AMR line item, citing generic note H, which will manage loss of material due to pitting, crevice, and microbiologically-influenced corrosion for stainless steel piping and fittings with the Buried Non-Steel Piping Inspection Program. The staff finds the applicant's proposal to manage these components with the Buried Non-Steel Piping Inspection Program acceptable because the visual inspections conducted by this program will detect loss of material due to pitting, crevice, and microbiologically-influenced corrosion. The staff reviewed LRA Sections 2.3.4 and 3.4 and the UFSAR supplement and confirmed that no other in-scope stainless steel piping, piping components, and piping elements exposed to soil are present in the steam and power conversion system and, therefore, finds the applicant's determination acceptable.

(3) LRA Section 3.4.2.2.7.3 refers to Table 3.4.1, item 3.4.1-18 and addresses loss of material due to pitting and crevice corrosion. The applicant stated that this aging effect is not applicable because HCGS does not have any copper alloy piping, piping components, and piping elements exposed to a lubricating oil environment in the steam and power conversion system.

SRP-LR Section 3.4.2.2.7.3 states that loss of material due to pitting and crevice corrosion could occur for copper alloy piping, piping components, and piping elements exposed to lubricating oil.

The staff reviewed the applicant's UFSAR supplement and finds that SRP-LR Section 3.4.2.2.7, item 3 is not applicable to HCGS because HCGS does not have any copper alloy piping, piping components, and piping elements exposed to a lubricating oil environment in the steam and power conversion system, and the staff guidance in this SRP-LR section is only applicable to BWR copper alloy piping, piping components, and piping elements exposed to a lubricating oil environment in the steam and power conversion system.

Based on the staff's review and evaluation of the applicant's programs, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.7 criteria. For those line items that apply to LRA Section 3.4.2.2.7, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.8 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion

LRA Section 3.4.2.2.8 refers to Table 3.4.1, item 3.4.1-19 and addresses loss of material due to pitting, crevice, and microbiologically-influenced corrosion. The applicant stated that this aging effect is not applicable because HCGS does not have any stainless steel piping, piping components, piping elements, or heat exchanger components exposed to a lubricating oil environment in the steam and power conversion system.

SRP-LR Section 3.4.2.2.8 states that loss of material due to pitting, crevice, and microbiologically-influenced corrosion could occur in stainless steel piping, piping components, piping elements, or heat exchanger components exposed to lubricating oil.

The staff reviewed the applicant's UFSAR supplement and finds that SRP-LR Section 3.4.2.2.8 is not applicable to HCGS because HCGS does not have any stainless steel piping, piping components, piping elements, or heat exchanger components exposed to a lubricating oil environment in the steam and power conversion system, and the staff guidance in this SRP-LR section is only applicable to BWR stainless steel piping, piping components, piping elements, or heat exchanger components exposed to a lubricating oil environment in the steam and power conversion system.

3.4.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Galvanic Corrosion

The staff reviewed LRA Section 3.4.2.2.9 against the criteria in SRP-LR Section 3.4.2.2.9.

LRA Section 3.4.2.2.9 refers to LRA Table 3.4.1, item 3.4.1-5 and addresses steel heat exchanger components exposed to treated water which are being managed for loss of material due to general, pitting, crevice, and galvanic corrosion by the Water Chemistry and One-Time Inspection programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the effectiveness of the Water Chemistry Program to manage this aging effect will be verified through inspections at susceptible locations through the One-Time Inspection Program.

The staff reviewed LRA Section 3.4.2.2.9 against the criteria in SRP-LR Section 3.4.2.2.9, which states that the existing AMP relies on monitoring and controlling water chemistry to manage the effects of loss of material due to general, pitting, and crevice corrosion; however, control of water chemistry does not preclude loss of material due to general, pitting, and crevice corrosion at locations of stagnant flow conditions. The SRP-LR also states that the effectiveness of water chemistry controls should be verified to ensure that corrosion is not occurring and that a one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion does not occur.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection programs is documented in SER Sections 3.0.3.2.1 and 3.0.3.1.11, respectively. In its review of components associated with item 3.4.1-5, the staff finds the applicant's proposal to manage aging using the above programs acceptable because: (1) the Water Chemistry Program provides for periodic sampling of treated water to maintain contaminants at acceptable limits to preclude this aging effect, and (2) the One-Time Inspection Program will inspect select components exposed to treated water for loss of material due to pitting and crevice corrosion to verify the effectiveness of the Water Chemistry Program.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.9 criteria. For those line items that apply to LRA Section 3.4.2.2.9, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.10 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA program.

3.4.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.4.2-1 through 3.4.2-4, the staff reviewed additional details of AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.4.2-1 through 3.4.2-4, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information concerning how the aging effects will be managed. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicate that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the aging effects will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.4.2.3.1 Steam and Power Conversion System – Condensate Storage and Transfer System – Summary of Aging Management Evaluation – LRA Table 3.4.2-1

The staff reviewed LRA Table 3.4.2-1, which summarizes the results of AMRs for the condensate storage and transfer system component groups.

In LRA Tables 3.4.2-1 and 3.3.2-10, the applicant stated that stainless steel piping and fittings exposed externally to soil are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion by the Buried Non-Steel Piping Inspection Program. The AMR line items cite generic note H, which indicates that the aging effect is not addressed in the GALL Report for this component, material, and environment combination.

The staff reviewed the applicant's Buried Non-Steel Piping Inspection Program and its evaluation is documented in SER Section 3.0.3.3.4. The staff finds the applicant's proposed program acceptable to manage aging for these components because it uses opportunistic and focused visual inspections of coatings and the base metal to detect loss of material due to pitting, crevice, and microbiologically-influenced corrosion.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.4.2-1, the applicant stated that stainless steel tanks exposed externally to soil are being managed for loss of material by the Aboveground Non-Steel Tanks Program. The AMR line items cite generic note G, which indicates that the environment is not addressed in the GALL Report for the component and material.

The staff reviewed the applicant's Aboveground Non-Steel Tanks Program and its evaluation is documented in SER Section 3.0.3.3.3. The staff finds the applicant's proposed program acceptable to manage loss of material for these components because it performs visual inspections of the exterior surfaces of the tank, as well as thickness measurements of the tank bottom to detect loss of material.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.3.2 Steam and Power Conversion System – Feedwater System – Summary of Aging Management Evaluation – LRA Table 3.4.2-2

The staff reviewed LRA Table 3.4.2-2, which summarizes the results of AMR evaluations for the feedwater system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.4.2.1.

3.4.2.3.3 Steam and Power Conversion System – Main Condenser System – Summary of Aging Management Evaluation – LRA Table 3.4.2-3

The staff reviewed LRA Table 3.4.2-3, which summarizes the results of AMRs for the main condenser system component groups.

In LRA Table 3.4.2-3, the applicant stated that carbon steel main condenser shells exposed externally to indoor air or internally to steam have no AERMs. The AMR line items cite generic note J, indicating that neither the component nor the material and environment combination is in the GALL Report. The AMR line items also cite plant-specific note 1, which states that the main condenser is within the scope of license renewal because it performs the post-accident function of providing a holdup volume for activity products and does not need to be leak tight or capable of maintaining a vacuum to perform this function. The applicant also stated that its radiological analysis assumes condenser vacuum is lost with a 1 percent per day leak rate. The applicant further stated that normal plant operation assures adequate condenser pressure boundary integrity and, therefore, the post-accident intended function to provide a holdup volume is assured.

The staff reviewed the applicant's current UFSAR supplement and confirmed that the main condenser has no safety-related functions. The staff finds the applicant's claim that the main condenser shells have no AERM acceptable because the main condenser's integrity is continually verified during normal plant operation and, therefore, its post-accident function as a holdup volume is continuously assured.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.4.2-3, the applicant stated that aluminum bronze main condenser tubesheets exposed internally to raw water or externally to steam have no AERMs. The AMR line items cite generic note J, indicating that neither the component nor the material and environment combination is in the GALL Report. The AMR line items also cite plant-specific note 1, which states that the main condenser is within the scope of license renewal because it performs the post-accident function of providing a holdup volume for activity products and does not need to be leak tight to perform this function.

The applicant also stated its radiological analysis assumes the condenser is isolated and vacuum is lost with a 1 percent per day leakage, which does not challenge the pressure boundary integrity of the condenser. The applicant further stated that since normal plant operation assures adequate condenser pressure boundary integrity, the post-accident intended function to provide holdup volume is assured.

The staff reviewed the applicant's UFSAR supplement and confirmed that the main condenser has no safety-related functions. The staff finds the applicant's claim that the main condenser tubesheets have no AERM acceptable because the main condenser's integrity is continually verified during normal plant operation and, therefore, its post-accident function as a holdup volume is continuously assured.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.4.2-3, the applicant stated that the titanium main condenser tube components exposed to raw water (internal) or steam (external) is not addressed by the GALL Report. The applicant referenced note J for this item, indicating that neither the component nor the material and environment combination is evaluated in the GALL Report. The applicant also stated that no AMP is needed for this component, material, and environment combination. The applicant further stated in plant-specific footnote 1 that the post-accident intended function of the main condenser is to provide a holdup volume which does not require the condenser to be leak-tight because the radiological analysis assumes the condenser is isolated and vacuum is lost, with 1 percent per day leakage, and this function is proven during plant operations on a continuous basis by maintaining a vacuum.

The staff confirmed that the GALL Report does not include an AERM or AMP for titanium alloy tube components exposed to raw water (internal) or steam (external) environments.

The staff notes that based on multiple references (e.g., AZo Journal of Materials Online, Britannica Encyclopedia, Key to Metals Database (online) Article 24), titanium is resistant to pitting, general, and crevice corrosion and SCC in salt water and turbine exhaust steam environments in essence due to its formation of very stable, continuous, highly adherent, and protective oxide films on metal surfaces. Based on these references, the staff also notes that due to its corrosion resistance capabilities, it is widely used in the refinery industry for condenser tubing and the aerospace industry in temperature applications up to 600°C. The staff finds the applicant's proposal that there are no other AERMs, other than the reduction of heat transfer, acceptable based on titanium's resistance to pitting, general, and crevice corrosion and SCC in raw water internal and steam external environment.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.3.4 Steam and Power Conversion System – Main Steam System – Summary of Aging Management Evaluation – LRA Table 3.4.2-4

The staff reviewed LRA Table 3.4.2-4, which summarizes the results of AMRs for the main steam system component groups.

The staff's review did not find any line items indicating plant-specific Notes F through J whereby the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.4.2.1.

3.4.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components within the scope of license renewal and 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, as required by 10 CFR 54.21(a)(3).

3.5 Aging Management of Containments, Structures, and Component Supports

This section of the SER documents the staff's review of the applicant's AMR results for the containments, structures, and component supports groups of:

- auxiliary boiler building
- auxiliary building control/diesel generator area
- auxiliary building service/radwaste area
- component supports commodity group
- fire water pump house
- piping and component insulation commodity group
- primary containment
- reactor building
- service water intake structures
- shoreline protection and dike
- switchyard
- turbine building
- yard structures

3.5.1 Summary of Technical Information in the Application

LRA Section 3.5 provides AMR results for the containment, structures, and component supports groups. LRA Table 3.5-1, "Summary of Aging Management Evaluations for Structures and Component Supports," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the structures and component supports groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.5.2 Staff Evaluation

The staff reviewed LRA Section 3.5 to determine whether the applicant has provided sufficient information to demonstrate that the effects of aging for the containment, structures, and component supports within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's evaluation are discussed in SER Section 3.5.2.1.

The staff also reviewed AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.5.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 3.5.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.5.2.3.

For SSCs which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.5-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.5 and addressed in the GALL Report.

Table 3.5-1 Staff Evaluation for Containments, Structures, and Component Supports in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
PWR Concrete (Reinforced and Prestressed) and Steel Containments BWR Concrete and Steel (Mark I, II, and III) Containments					
Concrete elements: walls, dome, basemat, ring girder, buttresses, containment (as applicable) (3.5.1-1)	Aging of accessible and inaccessible concrete areas due to aggressive chemical attack and corrosion of embedded steel	ISI (IWL) and for inaccessible concrete, an examination of representative samples of below-grade concrete and periodic monitoring of groundwater if environment is non-aggressive. A plant-specific program is to be evaluated if environment is aggressive.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete elements: All (3.5.1-2)	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring Program. If a dewatering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the dewatering system through the period of extended operation.	Yes	Not applicable Structures Monitoring Program	Not applicable to HCGS (See SER Section 3.5.2.2.1) Consistent with GALL Report (See SER Section 3.5.2.2.1)
Concrete elements: foundation, subfoundation (3.5.1-3)	Reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring Program. If a dewatering system is relied upon to control erosion of cement from porous concrete subfoundations, then the licensee is to ensure proper functioning of the dewatering system through the period of extended operation.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.1.1)
Concrete elements: dome, wall, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable) (3.5.1-4)	Reduction of strength and modulus of concrete due to elevated temperature	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel elements: drywell; torus; drywell head; embedded shell and sand pocket regions; drywell support skirt; torus ring girder; downcomers; liner plate, ECCS suction header, support skirt, region shielded by diaphragm floor, suppression chamber (as applicable) (3.5.1-5)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	Yes	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Structures Monitoring Program	Consistent with GALL Report (See SER Sections 3.5.2.1.4 and 3.5.2.1)
Steel elements: steel liner, liner anchors, integral attachments (3.5.1-6)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.1.1)
Prestressed containment tendons (3.5.1-7)	Loss of prestress due to relaxation, shrinkage, creep, and elevated temperature	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.1.1)
Steel and stainless steel elements: vent line, vent header, vent line bellows; downcomers (3.5.1-8)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (See SER Section 3.5.2.2.1)
Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers (3.5.1-9)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (See SER Section 3.5.2.2.1)
Stainless steel penetration sleeves, penetration bellows, dissimilar metal welds (3.5.1-10)	Cracking due to SCC	ISI (IWE) and 10 CFR Part 50, Appendix J and additional appropriate examinations/ evaluations for bellows assemblies and dissimilar metal welds.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel vent line bellows (3.5.1-11)	Cracking due to SCC	ISI (IWE) and 10 CFR Part 50, Appendix J and additional appropriate examination/ evaluation for bellows assemblies and dissimilar metal welds.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.2.1)
Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers (3.5.1-12)	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J and supplemented to detect fine cracks	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.2.1)
Steel, stainless steel elements, dissimilar metal welds: torus; vent line; vent header; vent line bellows; downcomers (3.5.1-13)	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J and supplemented to detect fine cracks	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.2.1)
Concrete elements: dome, wall, basemat ring girder, buttresses, containment (as applicable) (3.5.1-14)	Loss of material (scaling, cracking, and spalling) due to freeze-thaw	ISI (IWL). Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.1.1)
Concrete elements: walls, dome, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable) (3.5.1-15)	Cracking due to expansion and reaction with aggregate; increase in porosity, permeability due to leaching of calcium hydroxide	ISI (IWL) for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Seals, gaskets, and moisture barriers (3.5.1-16)	Loss of sealing and leakage through containment due to deterioration of joint seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	ISI (IWE) and 10 CFR Part 50, Appendix J	No	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with GALL Report
Personnel airlock, equipment hatch and CRD hatch locks, hinges, and closure mechanisms (3.5.1-17)	Loss of leak tightness in closed position due to mechanical wear of locks, hinges, and closure mechanisms	10 CFR Part 50, Appendix J and plant TSs	No	10 CFR Part 50, Appendix J and TSs	Consistent with GALL Report
Steel penetration sleeves and dissimilar metal welds; personnel airlock, equipment hatch, and CRD hatch (3.5.1-18)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	No	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with GALL Report
Steel elements: stainless steel suppression chamber shell (inner surface) (3.5.1-19)	Cracking due to SCC	ISI (IWE) and 10 CFR Part 50, Appendix J	No	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.1.1)
Steel elements: suppression chamber liner (interior surface) (3.5.1-20)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	No	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.1.1)
Steel elements: drywell head and downcomer pipes (3.5.1-21)	Fretting or lock-up due to mechanical wear	ISI (IWE)	No	ASME Section XI, Subsection IWE	Consistent with GALL Report
Prestressed containment: tendons and anchorage components (3.5.1-22)	Loss of material due to corrosion	ISI (IWL)	No	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
All Groups except Group 6: interior and above-grade exterior concrete (3.5.1-23)	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring Program	Yes	Structures Monitoring Program Fire Protection Program	Consistent with GALL Report (See SER Sections 3.5.2.1.5, 3.5.2.2.1, and 3.5.2.2.2)
All Groups except Group 6: interior and above-grade exterior concrete (3.5.1-24)	Increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring Program	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.2.2)
All Groups except Group 6: steel components: all structural steel (3.5.1-25)	Loss of material due to corrosion	Structures Monitoring Program. If protective coatings are relied upon to manage the effects of aging, the Structures Monitoring Program is to include provisions to address protective coating monitoring and maintenance.	Yes	Structures Monitoring Program Protective Coating Monitoring and Maintenance Program	Consistent with GALL Report (See SER Section 3.5.2.2.2)
All Groups except Group 6: accessible and inaccessible concrete: foundation (3.5.1-26)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring Program. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Yes	Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.5.2.2.2)
All Groups except Group 6: accessible and inaccessible interior/exterior concrete (3.5.1-27)	Cracking due to expansion due to reaction with aggregates	Structures Monitoring Program. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes	Not applicable Structures Monitoring Program	Not applicable to HCGS (See SER Section 3.5.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 1-3, 5-9: All (3.5.1-28)	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring Program. If a dewatering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the dewatering system through the period of extended operation.	Yes	Structures Monitoring Program Fire Protection Program	Consistent with GALL Report (See SER Sections 3.5.2.1.6 and 3.5.2.2.2)
Groups 1-3, 5-9: foundation (3.5.1-29)	Reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring Program. If a dewatering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the dewatering system through the period of extended operation.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.2.2)
Group 4: radial beam seats in BWR drywell; RPV support shoes for PWR with nozzle supports; steam generator supports (3.5.1-30)	Lock-up due to wear	ISI (IWF) or Structures Monitoring Program	Yes	Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.5.2.2.2)
Groups 1-3, 5, 7-9: below-grade concrete components, such as exterior walls below grade and foundation (3.5.1-31)	Increase in porosity and permeability, cracking, loss of material (spalling, scaling), aggressive chemical attack; cracking, loss of bond, and loss of material (spalling, scaling), corrosion of embedded steel	Structures Monitoring Program; examination of representative samples of below-grade concrete, and periodic monitoring of groundwater, if the environment is non-aggressive. A plant-specific program is to be evaluated if environment is aggressive.	Yes	Structures Monitoring Program Buried Non-Steel Piping Inspection	Consistent with GALL Report (See SER Sections 3.5.2.1.8 and 3.5.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 1-3, 5, 7-9: exterior above and below-grade reinforced concrete foundations (3.5.1-32)	Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide	Structures Monitoring Program for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes	Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.5.2.2.2)
Groups 1-5: concrete (3.5.1-33)	Reduction of strength and modulus due to elevated temperature	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.2.2)
Group 6: concrete; all (3.5.1-34)	Increase in porosity and permeability, cracking, loss of material due to aggressive chemical attack; cracking, loss of bond, loss of material due to corrosion of embedded steel	Inspection of Water-Control Structures or Federal Energy Regulatory Commission (FERC)/U.S. Army Corps of Engineers dam inspections and maintenance programs and for inaccessible concrete, an examination of representative samples of below-grade concrete, and periodic monitoring of groundwater, if the environment is non-aggressive. A plant-specific program is to be evaluated if environment is aggressive.	Yes	RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"" Buried Non-Steel Piping Inspection	Consistent with GALL Report (See SER Section 3.5.2.1.8)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: exterior above and below-grade concrete foundation (3.5.1-35)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance programs. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Yes	RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants""	Consistent with GALL Report (See SER Section 3.5.2.2.2)
Group 6: all accessible and inaccessible reinforced concrete (3.5.1-36)	Cracking due to expansion/ reaction with aggregates	Accessible areas: Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes	Not applicable Structures Monitoring Program and RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants""	Not applicable to HCGS (See SER Section 3.5.2.2.2) Consistent with GALL Report (See SER Section 3.5.2.2.2)
Group 6: exterior above and below-grade reinforced concrete foundation interior slab (3.5.1-37)	Increase in porosity and permeability, loss of strength due to leaching of calcium hydroxide	For accessible areas, Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes	RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"" Open-Cycle Cooling Water Program	Consistent with GALL Report (See SER Sections 3.5.2.1.8 and 3.5.2.2.2)
Groups 7, 8: tank liners (3.5.1-38)	Cracking due to SCC and loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-39)	Loss of material due to general and pitting corrosion	Structures Monitoring Program	Yes	Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.5.2.2.2)
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates (3.5.1-40)	Reduction in concrete anchor capacity due to local concrete degradation, service-induced cracking, or other concrete aging mechanisms	Structures Monitoring Program	Yes	Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.5.2.2.2)
Vibration isolation elements (3.5.1-41)	Reduction or loss of isolation function, radiation hardening, temperature, humidity, sustained vibratory loading	Structures Monitoring Program	Yes	Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.5.2.2.2)
Groups B1.1, B1.2, and B1.3: support members: anchor bolts, welds (3.5.1-42)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.2.2)
Groups 1-3, 5, 6: all masonry block walls (3.5.1-43)	Cracking due to restraint shrinkage, creep, and aggressive environment	Masonry Wall Program	No	Structures Monitoring Program Masonry Wall Program Fire Protection Program	Consistent with GALL Report (See SER Section 3.5.2.1.7)
Group 6: elastomer seals, gaskets, and moisture barriers (3.5.1-44)	Loss of sealing due to deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	Structures Monitoring Program	No	Structures Monitoring Program	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: exterior above- and below-grade concrete foundation; interior slab (3.5.1-45)	Loss of material due to abrasion and cavitation	Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance	No	RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"" Open-Cycle Cooling Water Program	Consistent with GALL Report (See SER Section 3.5.2.1.8)
Group 5: fuel pool liners (3.5.1-46)	Cracking due to SCC and loss of material due to pitting and crevice corrosion	Water Chemistry and monitoring of spent fuel pool water level in accordance with TSs and leakage from the leak chase channels	No	Water Chemistry and monitoring of spent fuel pool water level in accordance with TSs and leakage from the leak chase channels	Consistent with GALL Report
Group 6: all metal structural members (3.5.1-47)	Loss of material due to general (steel only), pitting, and crevice corrosion	Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance. If protective coatings are relied upon to manage aging, protective coating monitoring and maintenance provisions should be included.	No	RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"" Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.2.2.1.4)
Group 6: earthen water control structures – dams, embankments, reservoirs, channels, canals, and ponds (3.5.1-48)	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage	Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance programs	No	RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"	Consistent with GALL Report
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-49)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and ISI (IWF)	No	Water Chemistry and ASME Section XI, Subsection IWF	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups B2 and B4: galvanized steel, aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure (3.5.1-50)	Loss of material due to pitting and crevice corrosion	Structures Monitoring Program	No	Structures Monitoring Program Open-Cycle Cooling Water Program, Periodic Inspection, Aboveground Steel Tanks, Aboveground Non-Steel Tanks, and Fire Protection Program	Consistent with GALL Report (See SER Section 3.5.2.1.4)
Group B1.1: high-strength low-alloy bolts (3.5.1-51)	Cracking due to SCC and loss of material due to general corrosion	Bolting Integrity	No	ASME Section XI, Subsection IWF	Consistent with GALL Report (See SER Section 3.5.2.1.4)
Groups B2, and B4: sliding support bearings and sliding support surfaces (3.5.1-52)	Loss of mechanical function due to corrosion, distortion, dirt, overload, and fatigue due to vibratory and cyclic thermal loads	Structures Monitoring Program	No	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.1.1)
Groups B1.1, B1.2, and B1.3: support members: welds; bolted connections; support anchorage to building structure (3.5.1-53)	Loss of material due to general and pitting corrosion	ISI (IWF)	No	ASME Section XI, Subsection IWF	Consistent with GALL Report
Groups B1.1, B1.2, and B1.3: constant and variable load spring hangers; guides; stops (3.5.1-54)	Loss of mechanical function due to corrosion, distortion, dirt, overload, and fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	No	ASME Section XI, Subsection IWF	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, galvanized steel, and aluminum support members; welds; bolted connections; support anchorage to building structure (3.5.1-55)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Not applicable	Not applicable to BWRs (See SER Section 3.5.2.1.1)
Groups B1.1, B1.2, and B1.3: sliding surfaces (3.5.1-56)	Loss of mechanical function due to corrosion, distortion, dirt, overload, and fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	No	ASME Section XI, Subsection IWF	Consistent with GALL Report
Groups B1.1, B1.2, and B1.3: vibration isolation elements (3.5.1-57)	Reduction or loss of isolation function, radiation hardening, temperature, humidity, and sustained vibratory loading	ISI (IWF)	No	Not applicable	Not applicable to HCGS (See SER Section 3.5.2.1.1)
Galvanized steel and aluminum support members; welds; bolted connections; support anchorage to building structure exposed to air – indoor uncontrolled (3.5.1-58)	None	None	No	None	Consistent with GALL Report (See SER Section 3.5.2.1.9)
Stainless steel support members; welds; bolted connections; support anchorage to building structure (3.5.1-59)	None	None	No	None	Consistent with GALL Report

The staff's review of the containments, structures, and component supports groups followed several approaches. One approach, documented in SER Section 3.5.2.1, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.5.2.2, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.5.2.3, discusses the staff's review of AMR results for components the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the containments, structures, and component supports is documented in SER Section 3.0.3.

3.5.2.1 AMR Results That Are Consistent with the GALL Report

LRA Section 3.5.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the structures and structural components and their commodity groups:

- 10 CFR Part 50, Appendix J
- ASME Section XI, Subsection IWE
- ASME Section XI, Subsection IWF
- One-Time Inspection
- Periodic Inspection
- Protective Coating Monitoring and Maintenance Program
- RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"
- Structures Monitoring Program
- TLAA
- Water Chemistry

Although not identified directly in LRA Section 3.5.2.1, LRA Table 3.5.1 identifies the following additional programs under the discussion column that manage aging effects for the structures and structural components and their commodity groups for specified conditions:

- Aboveground Steel Tanks
- Aboveground Non-Steel Tanks
- Buried Non-Steel Piping Inspection
- Fire Protection Program
- Masonry Wall Program
- Open-Cycle Cooling Water Program

In LRA Tables 3.5.2-1 through 3.5.2-13, the applicant summarized AMRs for structures and component supports and indicated AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the LRA for which the applicant claimed consistency with the GALL Report and for which the GALL Report does not recommend further evaluation, the staff's audit and review determined whether the plant-specific components groups were bounded by the GALL Report evaluation.

For each AMR line item, the applicant noted how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with Notes A through E indicating how the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff reviewed these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff reviewed these line items to verify consistency with the GALL Report and verified that the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the staff verified that the AMP is consistent with the GALL Report AMP. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified a different component with the same material, environment, aging effect, and AMP as the component under review. The staff reviewed these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff reviewed these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review and verified whether the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the credited AMP would manage the aging effect consistently with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

The staff reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

The staff reviewed the LRA to confirm that the applicant: (a) provided a brief description of the system, components, materials, and environments; (b) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (c) identified those aging effects for the structures and structural components and their commodity groups that are subject to an AMR. On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.5.1, the applicant's references to the GALL Report are acceptable and no further staff review is required, with the exception of the following AMRs that the applicant had identified were consistent with the AMRs of the GALL Report and for which the staff determined were in need of additional clarification and assessment. The staff's evaluations of these AMRs are provided in the subsections that follow.

LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-3, 3.5.2-4, 3.5.2-5, 3.5.2-7, 3.5.2-8, 3.5.2-9, 3.5.2-11, 3.5.2-12, and 3.5.2-13 were revised as a result of the response to RAI B.2.1.12-01, dated June 14, 2010. The revision added AMR items in these tables to reference the applicant's Bolting Integrity Program to manage the aging for bolting AMR items. Existing bolting AMR items which reference other AMPs are used in conjunction with the added bolting AMR items to properly manage aging for bolting components. The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.4. The staff notes that the Bolting Integrity Program is supplemented by other AMPs including but not limited to: the Structures Monitoring, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems, External Surfaces Monitoring, and Buried Piping Inspection programs. These other AMPs supplement the Bolting Integrity Program by implementing the requirements of the Bolting Integrity Program for pressure retaining bolted joints, component support bolting, and structural bolting within the scope of license renewal. The applicant's action revised the LRA to add bolting component items in the tables mentioned above that are consistent with the GALL Report and have designated them as such with generic note B.

3.5.2.1.1 AMR Results Identified as Not Applicable

In LRA Table 3.5.1, items 3.5.1-1, 3.5.1-3, 3.5.1-6, 3.5.1-7, 3.5.1-14, 3.5.1-15, 3.5.1-19, 3.5.1-20, 3.5.1-22, and 3.5.1-55, the applicant stated that the corresponding AMR items in the GALL Report are not applicable to HCGS because HCGS is a BWR design that incorporates a Mark I steel containment and the AMR items in the GALL Report are only applicable to particular components of BWR or PWR designs that use a concrete containment or containment designs that use a post-tensioning system. The staff verified that the stated AMR items in the GALL Report are only applicable to concrete components of PWR designs or post-tensioned concrete containments and are not applicable to HCGS.

In LRA Table 3.5.1, items 3.5.1-52 and 3.5.1-57, the applicant stated that the corresponding AMR items in the GALL Report are not applicable since the component, material, environment, and aging effect or mechanism does not apply for HCGS. For each of these line items, the staff reviewed the LRA and UFSAR supplement and confirmed the applicant's claim that the component, material, environment, and aging effect or mechanism does not apply for HCGS. Since HCGS does not have the component, material, environment, and aging effect or mechanism for these Table 1 line items, the staff finds that these AMRs are not applicable to HCGS.

The remaining items identified as not applicable require further evaluation and are discussed in the corresponding subsections of SER Section 3.5.2.2.

3.5.2.1.2 Loss of Preload Due to Self-Loosening

In the LRA Table 3.5.2-1 through 3.5.2-5, 3.5.2-7, 3.5.2-8, 3.5.2-11, and 3.5.2-12 line items that reference Table 3.3-1, item 3.3.1-45, and LRA Table 3.5.2-7 line items that reference Table 3.1-1, item 3.1.1-52, the applicant included a reference to Note E and credits the Structures Monitoring Program for managing this aging effect or mechanism in an air – indoor environment for carbon and low alloy steel bolting, galvanized steel bolting, and stainless steel bolting. The applicant also included either plant-specific Notes 1, 2, 3, or 5. Plant-specific Note 1 (Tables 3.5.2-1, 3.5.2-2, 3.5.2-3, 3.5.2-5, 3.5.2-8, 3.5.2-11, and 3.5.2-12), plant-specific Note 3 (Table 3.5.2-4), and plant-specific Note 2 (Table 3.5.2-7) each state:

> Based on industry standards and operating experience[,] age related loss of preload/self-loosening of structural bolting could be caused by vibration, flexing of the joint or cyclic shear loads that could occur in any environment. However, these causes are considered in the design of structural connections and eliminated by the initial preload bolt torquing. Thus, loss of preload/self-loosening of structural bolting is not significant and will not impact structural intended functions. Nevertheless, loss of preload/self-loosening will be monitored through the Structures Monitoring Program.

Plant-specific Note 5 (Table 3.5.2-4) and plant-specific Note 3 (Table 3.5.2-7) each state that, "[The] Structures Monitoring Program is [an] applicable aging management program for this component."

The applicant stated that components have been aligned to this item number based on material, environment, and aging effect.

The staff reviewed the AMR results lines that reference Note E and plant-specific Notes 1, 2, 3, or 5. The staff determined, for these items, that the component type, material, environment, and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," the applicant proposed using the Structures Monitoring Program.

The LRA states that these components have the intended function of structural support and are examined using the Structures Monitoring Program as the primary AMP. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds the applicant's use of the Structures Monitoring Program acceptable because the program: (1) monitors exposed surfaces of bolting for loss of material due to corrosion, loose nuts, missing bolts, or other indications of loss of preload; and (2) incorporates procedures based on EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide," to ensure proper specification of bolting material, lubricant, and installation torque. The staff finds that the applicant addressed the AERM adequately.

In the LRA Table 3.5.2-4 line items that reference Table 3.3-1, item 3.3.1-45, the applicant included a reference to Note E and credits the ASME Section XI, Subsection IWF Program for managing this aging effect or mechanism in an air – indoor environment for high-strength low alloy steel bolting with yield strength greater than 150 ksi, carbon and low alloy steel bolting, and galvanized steel bolting. The applicant also included plant-specific Notes 1, 2, and 3 for the high-strength low alloy steel bolting and plant-specific Notes 1 and 3 for the carbon and low alloy steel bolting and galvanized steel bolting. Plant-specific Note 1 states, "ASME Section XI, Subsection IWF is the applicable aging management program for this component." Plant-specific Note 2 states:

> NSSS Class 1 component supports (reactor pressure vessel support) utilize high strength ASTM A490 bolts (actual yield strength could be greater than or equal [to] 150 ksi). The bolts are not subject to high-sustained preload stress, aggressive environment, and lubricants containing contaminants not approved for use. Additionally ASTM A490 bolts have high resistance to stress corrosion cracking due to their ductility and industry and plant specific operating experience have not identified stress corrosion cracking of ASTM A490 bolts as a concern. Therefore cracking due to stress corrosion cracking is not an aging effect requiring management. Loss of material is the only aging effect requiring aging

> management. They are monitored for loss of material due to corrosion and loss of preload by visual inspection using ASME Section XI, Subsection IWF.

Plant-specific Note 3 states:

> Based on industry standards and operating experience[,] age related loss of preload/self-loosening of structural bolting could be caused by vibration, flexing of the joint or cyclic shear loads that could occur in any environment. However, these causes are considered in the design of structural connections and eliminated by the initial preload bolt torquing. Thus, loss of preload/self-loosening of structural bolting is not significant and will not impact structural intended functions. Nevertheless, loss of preload/self-loosening will be monitored through the applicable aging management program.

The applicant stated that components have been aligned to this item number based on material, environment, and aging effect.

The staff reviewed the AMR results lines that reference Note E and plant-specific Notes 1, 2, and 3. The staff determined, for these items, that the component type, material, environment, and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M18, “Bolting Integrity,” the applicant proposed using the ASME Section XI, Subsection IWF Program.

The LRA states that these components have the intended function of structural support and are examined using the ASME Section XI, Subsection IWF Program as the primary AMP. The staff’s review of the ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.1.15. The staff finds the applicant’s use of the ASME Section XI, Subsection IWF Program acceptable because the program: (1) provides periodic visual examinations of ASME Code Section XI Class 1, 2, 3, and MC piping and component support members for loss of material and loss of mechanical function, including inspection of bolting for supports for loss of material and for loss of preload by inspecting for missing, detached, or loosened bolts and nuts; and (2) relies on design change procedures that are based on EPRI TR-104213 guidance to ensure proper specification of bolting material, lubricant, and installation torque. The staff finds that the applicant addressed the AERM adequately.

In the LRA Table 3.5.2-9 line items that reference Table 3.3-1, item 3.3.1-45, the applicant included a reference to Note E and credits the RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants Program” for managing this aging effect or mechanism in an air – indoor environment for carbon and low alloy steel bolting and galvanized bolting. The applicant also included plant-specific Note 1 which states:

> Based on industry standards and operating experience[,] age related loss of preload/self-loosening of structural bolting could be caused by vibration, flexing of the joint or cyclic shear loads that could occur in any environment. However, these causes are considered in the design of structural connections and eliminated by the initial preload bolt torquing. Thus, loss of preload/self-loosening of structural bolting is not significant and will not impact structural intended functions. Never the less, loss of preload/self-loosening will be monitored through the RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” aging management program.

The applicant stated that components have been aligned to this item number based on material, environment, and aging effect.

The staff reviewed the AMR results lines that reference Note E and plant-specific Note 1. The staff determined, for these items, that the component type, material, environment, and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M18, “Bolting Integrity,” the applicant proposed using the RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program.

The LRA states that these components have the intended function of structural support and the RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants Program” has been substituted to manage loss of preload due to self-loosening in steel bolting of the service water intake structure exposed to indoor air. The staff’s review of the applicant’s RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants Program” is documented in SER Section 3.0.3.2.17. The staff finds the applicant’s use of the RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program acceptable because the program: (1) is based on guidance provided in RG 1.127 and ACI 349.3R, (2) is implemented through the Structures Monitoring Program, and (3) addresses age-related deterioration of water control structures with respect to loss of material and loss of preload for steel and metal components. The staff finds that the applicant addressed the AERM adequately.

In the LRA Table 3.5.2-7 line items that reference Table 3.2-1, item 3.2.1-24, the applicant included a reference to Note E and credits the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs for managing this aging effect or mechanism in an air – indoor environment for carbon and low alloy steel bolting. The applicant also included plant-specific Note 1 which states, “ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J are the applicable aging management program[s] for this component.” The applicant stated that components have been aligned to this item number based on material, environment, and aging effect.

The staff reviewed the AMR results lines that reference Note E and plant-specific Note 1. The staff determined, for these items, that the component type, material, environment, and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M18, “Bolting Integrity,” the applicant proposed using the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs.

The LRA states that these components have the intended function of pressure boundary or structural support and that the 10 CFR Part 50, Appendix J and ASME Section XI, Subsection IWE programs have been substituted to manage loss of preload due to self-loosening in steel bolting exposed to indoor air. The staff’s reviews of the applicant’s 10 CFR Part 50, Appendix J and ASME Section XI, Subsection IWE programs are documented in SER Sections 3.0.3.1.16 and 3.0.3.2.14, respectively. The staff finds the applicant’s use of the 10 CFR Part 50, Appendix J and ASME Section XI, Subsection IWE programs acceptable because: (1) the 10 CFR Part 50, Appendix J Program provides for detection of age-related degradation of components comprising the containment pressure boundary due to aging effects such as loss of leak tightness, loss of material, cracking, loss of sealing, or loss of preload in various systems penetrating containment; and (2) the ASME Section XI, Subsection IWE Program conducts visual examinations (general visual and VT-3) and augmented inspections (VT-1) for evidence of aging effects that could affect leak tightness of the primary containment structure and includes the pressure-retaining bolting. The staff finds that the applicant addressed the AERM adequately.

3.5.2.1.3 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

In the LRA Table 3.5.2-9 and 3.5.2-10 line items that reference Table 3.3-1, item 3.3.1-19, the applicant included a reference to Note E and credited the RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program for managing this aging effect or mechanism in a groundwater or soil environment for carbon steel piles or sheet piles. The applicant also included plant-specific Notes 2 or 4 (depending on the table number) which each state, “RG 1.127, ‘Inspection of Water-Control Structures Associated with Nuclear Power Plants’ is [the] applicable aging management program for this component.”

The staff reviewed the AMR results lines that reference Note E and plant-specific Notes 2 or 4. The staff determined, for these items, that the material and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M28, “Buried Piping and Tanks Surveillance,” or GALL AMP XI.M34, “Buried Piping and Tanks Inspection,” the applicant proposed using the RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program.

The LRA states that these components have the intended functions of structural support or shelter and protection in the form of carbon steel piles or carbon steel sheet piles and are examined using the RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program. The staff’s review of the applicant’s RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program is documented in SER Section 3.0.3.2.17. GALL AMP XI.M28 applies to buried piping and tanks and includes surveillance measures to mitigate corrosion by protecting the external surface of buried carbon steel piping and tanks. GALL AMP XI.M34 also applies to buried piping and tanks and includes preventive measures to mitigate corrosion and periodic inspection to manage the effects of corrosion on the pressure retaining capacity of buried steel piping and tanks. The LRA also states that the carbon steel piles are located below foundations possibly making them inaccessible. However, the LRA states that degradation of piles will manifest in settlement distortion or cracking of concrete, and accessible concrete examinations will detect cracks and distortion of the structures. The LRA further states that studies have shown that steel piles driven into undisturbed natural soil are not appreciably affected by corrosion due to the oxygen deficiency in soil at a few feet below grade, piles driven into disturbed soil have been shown to experience only minor to moderate corrosion, and in either case, the observed loss of material due to corrosion was not considered significant enough to impact the intended function of the piles, which is consistent with NUREG-1557. In the LRA, the applicant further stated that the carbon steel sheet piles are one of the components in the shoreline protection and dike structures that provide protection against shoreline recession for the service water system SCs during and following design seismic and flood events. The staff finds the applicant’s use of RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program acceptable because: (1) the program is implemented under the Structures Monitoring Program and is based on guidance provided in RG 1.127 and ACI 349.3R; (2) the program includes provisions for examination of reinforced concrete members, structural steel, and earthen water-control structures of the service water structure and shoreline protection and dike structures; and (3) examinations of and accessible concrete will detect cracks and distortion of the structures due to settlement distortion or concrete cracking that would result from degradation of the piles. The staff finds that the applicant addressed the AERM adequately.

In the LRA Table 3.5.2-9 line items that reference Table 3.3-1, item 3.3.1-19, the applicant included a reference to Note E and credited the RG 1.127, “Inspection of Water-Control

Structures Associated with Nuclear Power Plants" Program for managing this aging effect or mechanism in a groundwater or soil environment for carbon steel and galvanized steel penetration sleeves in the service water intake structure. The applicant also included plant-specific Note 4 which states, RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" is the applicable aging management program for this component."

The staff reviewed the AMR results lines that reference Note E and plant-specific Note 4. The staff determined, for these items, that the material and aging effect are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M28, "Buried Piping and Tanks Surveillance," or GALL AMP XI.M34, "Buried Piping and Tanks Inspection," the applicant proposed using the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program.

The LRA states that the carbon steel or galvanized steel penetration sleeves have the intended function of structural support or flood barrier and are examined using the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program. The staff's review of the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program is documented in SER Section 3.0.3.2.17. GALL AMP XI.M28 applies to buried piping and tanks and includes surveillance measures to mitigate corrosion by protecting the external surface of buried carbon steel piping and tanks. GALL AMP XI.M34 also applies to buried piping and tanks and includes preventive measures to mitigate corrosion and periodic inspection to manage the effects of corrosion on the pressure retaining capacity of buried steel piping and tanks. Due to potential accessibility constraints associated with the penetration sleeves being located in a groundwater or soil environment, the staff is unclear how the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program, which is primarily a visual-based program, will be used to address the structure and aging effect combinations during the period of extended operation. By letter dated June 7, 2010, the staff issued RAI 3.5.2.1-2 to address this issue.

By letter dated June 29, 2010, the applicant explained that the penetration sleeves discussed above were aligned to GALL Report item 3.3.1-19 to show agreement between the LRA and the GALL Report with respect to the identified aging effects and mechanisms for the material and environment combination; the alignment was not intended to suggest consistency with the AMP recommended by the GALL Report. The applicant further explained that the recommended GALL Report programs are not applicable for aging management of the penetration sleeves because the recommended programs are specifically applicable to buried piping and buried tanks. These programs do not include activities that will effectively manage aging effects of penetration sleeve components to assure the associated structural intended functions are maintained. The applicant explained that the penetration sleeves are installed in concrete walls and the majority of the sleeve is located within the wall, while a small portion may protrude past the wall surface and into a soil environment. The applicant also explained that most of the sleeve is protected on both the outer and inner surface by concrete, grout, or elastomer seal material. The applicant explained the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program, implemented under the Structures Monitoring Program, is the appropriate program to manage these components, and it includes inspections of the penetration seals and the associated sleeves on a 5-year interval. These inspections will detect material degradation or indications of seal leakage prior to loss of intended function.

The staff reviewed the applicant's response and noted that the penetration sleeves are structural components embedded in concrete. Visual inspections from the indoor side of the wall, on a 5-year frequency, should be able to detect degradation prior to a loss of intended function. Based on its review, the staff finds the applicant's aging management approach acceptable because the RG 1.127, "Inspection of Water-Control Structures Program includes appropriate inspections to detect degradation of the penetration sleeves prior to loss of intended function. The staff finds that the applicant addressed the AERM adequately and the staff's concern in RAI 3.5.2.1-2 is resolved.

In the LRA Table 3.5.2-4, 3.5.2-7, and 3.5.2-8 line items that reference Table 3.5-1, item 3.5.1-47, the applicant included a reference to Note E and credited the Structures Monitoring Program for managing this aging effect or mechanism for carbon steel in a raw water or flowing water environment. The applicant also included either plant-specific Notes 2, 3, or 5 (depending on the table number) which each state, "[The] Structures Monitoring Program is the applicable aging management program for this component."

The staff reviewed the AMR results lines that reference Note E and plant-specific Notes 2, 3, and 5. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S7, RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," or the FERC/U.S. Army Corps of Engineers dam inspections and maintenance program, the applicant proposed using the Structures Monitoring Program.

The LRA states that the carbon steel supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, and non-ASME piping and components (support members, welds, bolted connections, support anchorages to building structure) and the sump liners have intended functions of either structural support or water retaining boundary and are examined using the Structures Monitoring Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds the applicant's use of the Structures Monitoring Program acceptable because the program: (1) performs visual inspections to monitor for indications of degradation such as loss of material, (2) includes water-control structures within its scope, (3) implements the guidance of GALL AMP XI.S7, and (4) has been enhanced to conduct the visual inspections on a frequency not to exceed 5 years. The staff finds that the applicant addressed the AERM adequately.

In the LRA Table 3.5.2-7 line items that reference Table 3.5-1, item 3.5.1-5, the applicant included a reference to Note E and credited the Structures Monitoring Program for managing this aging effect or mechanism for miscellaneous carbon steel components (catwalks, stairs, handrails, ladders, platforms, etc.) in a treated water environment. The applicant also included plant-specific Note 3 which states, "[The] Structures Monitoring Program is the applicable aging management program for this component."

The staff reviewed the AMR lines that reference Note E and plant-specific Note 3. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S1, "ASME Section XI, Subsection IWE," the applicant proposed using the Structures Monitoring Program.

The LRA states that the carbon steel components have an intended function of structural support and are examined using the Structures Monitoring Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. GALL AMP XI.S1 is intended to address Class MC pressure retaining components of steel containments and their integral attachments; metallic shell and penetration liners of Class CC (concrete containment) and their integral attachments; containment seals and gaskets; containment pressure retaining bolting; and metal containment surface areas, including welds and base metal. The staff finds the applicant's use of the Structures Monitoring Program acceptable because: (1) the carbon steel components are not part of the pressure retaining boundary, (2) the program performs visual inspections to monitor for indications of degradation such as loss of material, and (3) the program has been enhanced to conduct the visual inspections on a frequency not to exceed 5 years. The staff finds that the applicant addressed the AERM adequately.

In several LRA line items that reference Table 3.5-1, item 3.5.1-50, the applicant included a reference to Note E and credited the Periodic Inspection Program for managing loss of material due to general, pitting, and crevice corrosion in an air – outdoor environment for aluminum and stainless steel components.

The staff reviewed the AMR results lines that reference Note E. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring," the applicant proposed using the Periodic Inspection Program.

The LRA states that the Periodic Inspection Program is a condition monitoring program that manages aging of piping, piping components, piping elements, ducting components, tanks, and heat exchanger components, and includes provisions for periodic visual inspections of aluminum components to detect loss of material aging effects. The staff's review of the applicant's Periodic Inspection Program is documented in SER Section 3.0.3.3.2. The LRA also states that the visual inspections are conducted on a 10-year inspection frequency that has been established based on plant and industry operating experience. It is not clear to the staff that the scope of the applicant's Periodic Inspection Program includes all the components which credit it for management in the LRA. In addition, for components located in an air – outdoor environment, the program does not meet guidance such as provided in ACI 349.3R as referenced by GALL AMP XI.S6, which recommends an inspection frequency of 5 years. By letter dated June 7, 2010, the staff issued RAI 3.5.2.1-3 to address these issues.

By letter dated June 29, 2010, the applicant explained that the components referenced in RAI 3.5.2.1-3 were aligned to GALL Report item 3.5.1-50 to show agreement between the LRA and the GALL Report with respect to the identified aging effects and mechanisms for the material and environment combination; the alignment was not intended to suggest consistency with the AMP recommended by the GALL Report. The applicant explained that the recommended GALL Report program is not applicable for aging management of the mechanical piping system components. The program does not include appropriate activities for effectively managing the aging effects of mechanical piping system components. The applicant further explained that the Periodic Inspection Program is the appropriate program to manage aging of these components, and the program includes all the referenced items within its scope. The applicant further explained that the 10-year inspection frequency is appropriate for stainless steel and aluminum components exposed to outdoor air due to the corrosion resistance of the materials. The applicant explained that this conclusion was supported by plant-specific operating experience, including inspections of outdoor stainless steel piping in 2005 and 2007 which showed no signs of age-related degradation. These inspections suggest little to no age-related degradation after 20 years in service.

The staff reviewed the applicant's response and noted that all of the AMR line items in question are included within the scope of the applicant's Periodic Inspection Program. The staff also noted that the applicant provided justification for the 10-year inspection interval, based on plant-specific operating experience. Based on its review, the staff finds the applicant's use of the Periodic Inspection Program acceptable because it includes appropriate visual inspections at an appropriate frequency to detect degradation of aluminum and stainless steel components prior to a loss of intended function. The staff finds that the applicant addressed the AERM adequately and the staff's concern in RAI 3.5.2.1-3 is resolved.

In the LRA Table 3.3.2-10 line items that reference Table 3.5-1, item 3.5.1-50, the applicant included a reference to Note E and credited the Aboveground Steel Tanks Program for managing loss of material due to general, pitting, and crevice corrosion in an air – outdoor environment for stainless steel fire water storage tank heaters.

The staff reviewed the AMR results lines that reference Note E. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring," the applicant proposed using the Aboveground Steel Tanks Program.

The staff's review of the applicant's Aboveground Steel Tanks Program is documented in SER Section 3.0.3.2.9. It is unclear to the staff how the Aboveground Steel Tanks Program meets or exceeds the inspection requirements discussed in the GALL Report recommended program and how the applicant's credited program will be used to manage loss of material of the stainless steel fire water storage tank heaters. By letter dated June 7, 2010, the staff issued RAI 3.5.2.1-4 to address these issues.

The applicant responded by letter dated June 29, 2010, and explained that the fire water storage tank stainless steel electric heaters are active components and do not serve a passive intended function such as a pressure boundary. The applicant further explained that since the components are considered active, they are not subject to an AMR and they should not have been included in LRA Table 3.3.2-10. The applicant revised the LRA accordingly.

The staff reviewed the applicant's response and found it acceptable because the applicant considers the electric heaters active components without a passive intended function. Therefore, the components should have been "screened out" and should not have been subject to an AMR or included in LRA Table 3.3.2-10. The staff's concern in RAI 3.5.2.1-4 is resolved.

In the LRA Table 3.3.2-10 line items that reference Table 3.5-1, item 3.5.1-50, the applicant included a reference to Note E and credited the Fire Protection Program for managing loss of material due to general, pitting, and crevice corrosion in an air – outdoor environment for aluminum bird screens on the fire water tank vents.

The staff reviewed the AMR lines that reference Note E. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring," the applicant proposed using the Fire Protection Program.

The staff's review of the applicant's Fire Protection Program is documented in SER Section 3.0.3.2.7. It is unclear to the staff how the Fire Protection Program meets or exceeds the inspection requirements discussed in the GALL Report recommended program and how the applicant's credited program will be used to manage loss of material of the aluminum bird screens on the fire water tank vents. By letter dated June 7, 2010, the staff issued RAI 3.5.2.1-5 to address these issues.

The applicant responded by letter dated June 29, 2010, and explained that the aluminum bird screens in question are located on the roof vent pipe of the fire water storage tanks. The applicant further explained that the fire water storage tanks are within the scope of license renewal because they are relied upon to perform a function that demonstrates compliance with the NRC Fire Protection regulations; however, the aluminum bird screens are not relied upon to perform an intended function to demonstrate compliance with the regulations. Age-related degradation of the screens cannot prevent air flow through the vent pipe and will not impact the intended function of the fire water storage tank. Since the components do not have intended functions for license renewal, the applicant explained that they are not within the scope of license renewal and should not have been included in LRA Table 3.3.2-10. The applicant revised the LRA accordingly.

The staff reviewed the applicant's response and found it acceptable because it explained that degradation of the bird screens would not impact the intended function of the fire water storage tanks. The staff notes that loss of material due to corrosion of the bird screens would not impact the function of the vent pipe or the fire water storage tanks. Therefore, the staff finds that the components should not have been within the scope of license renewal and should not have been subject to an AMR or included in LRA Table 3.3.2-10. The staff's concern in RAI 3.5.2.1-5 is resolved.

In the LRA Table 3.4.2-1 line items that reference Table 3.5-1, item 3.5.1-50, the applicant included a reference to Note E and credited the Aboveground Non-Steel Tanks Program for managing loss of material due to general, pitting, and crevice corrosion in an air – outdoor environment for stainless steel components.

The staff reviewed the AMR lines that reference Note E. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring," the applicant proposed using the Aboveground Non-Steel Tanks Program.

The staff's review of the applicant's Aboveground Non-Steel Tanks Program is documented in SER Section 3.0.3.3.3. The staff noted that the Aboveground Non-Steel Tanks Program performs visual inspections to monitor for indications of degradation at a frequency of five 5 years or less. The GALL Report program recommends visual inspections at a frequency of 5 years or less for components exposed to an exterior environment. Since the applicant's credited program performs inspections which are equivalent to the GALL Report recommended program, the staff finds the applicant's use of the Aboveground Non-Steel Tanks Program acceptable. The staff finds that the applicant addressed the AERM adequately.

In the LRA Table 3.3.2-27 line items that reference Table 3.5-1, item 3.5.1-50, the applicant included a reference to Note E and credited the Open-Cycle Cooling Water System Program for managing loss of material due to general, pitting, and crevice corrosion in an air – outdoor environment for stainless steel components.

The staff reviewed the AMR results lines that reference Note E. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring," the applicant has proposed using the Open-Cycle Cooling Water System Program.

The staff's review of the applicant's Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.1.9. The Open-Cycle Cooling Water System Program is an existing program that manages the internal corrosion of piping. It is unclear to the staff how the Open-Cycle Cooling Water System Program meets or exceeds the inspection requirements discussed in the GALL Report recommended program and how the applicant's credited program will be used to manage loss of material of the external surfaces of the stainless steel components. By letter dated June 25, 2010, the staff issued RAI 3.5.2.1-7 to address these issues.

The applicant responded by letter dated July 20, 2010, and explained that the components referenced in RAI 3.5.2.1-7 were aligned to GALL Report item 3.5.1-50 to show agreement between the LRA and the GALL Report with respect to the identified aging effects and mechanisms for the material and environment combination; the alignment was not intended to suggest consistency with the AMP recommended by the GALL Report. The applicant explained that the recommended GALL Report program is not applicable for aging management of stainless steel pump casings or rupture disks. The program does not include appropriate activities for effectively managing the aging effects of the components. The applicant further explained that the Open-Cycle Cooling Water System Program includes component preventive maintenance activities which include condition monitoring that would detect loss of material on both internal and external surfaces. The applicant stated that these periodic maintenance activities will detect possible degradation prior to a loss of intended function.

The staff reviewed the applicant's response and found it acceptable because the applicant explained how preventive maintenance activities credited by the program can detect degradation due to loss of material. The preventive maintenance activities include visual inspections of the components for indications of loss of material. These inspections are equivalent to the guidance provided in the GALL Report recommended program. Since the applicant is inspecting the internal and external surfaces of the components for loss of material, the staff finds the applicant's aging management approach acceptable, and the staff's concern in RAI 3.5.2.1-7 is resolved.

In the LRA Table 3.5.2-7 line items that reference Table 3.2-1, item 3.2.1-23, the applicant included a reference to Note E and credited the ASME Section XI, Subsection IWE Program for managing this aging effect or mechanism for carbon and low alloy steel containment closure bolting in an air – indoor environment. The applicant also included plant-specific Note 1 which states, "ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J are the applicable aging management program for this component."

The staff reviewed the AMR results lines that reference Note E and plant-specific Note 1. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," the applicant proposed using the ASME Section XI, Subsection IWE Program.

The LRA states that these components have the intended function either of pressure boundary or structural support and are examined using the ASME Section XI, Subsection IWE Program as the primary AMP. In the LRA, the plant-specific note also states that the 10 CFR Part 50, Appendix J Program is also applicable to this component. The staff's reviews of the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs are documented in SER Sections 3.0.3.2.14 and 3.0.3.1.16, respectively. The staff finds the applicant's use of the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs acceptable because: (1) the ASME Section XI, Subsection IWE Program conducts general and detailed visual examinations and augmented inspections for evidence of aging effects that could affect leak tightness of the containment structure, including the pressure retaining components (includes bolting) and their integral attachments; and (2) the 10 CFR Part 50, Appendix J Program provides for detection of age-related degradation of components comprising the containment pressure boundary. The staff finds that the applicant addressed the AERM adequately.

In the LRA Table 3.5.2-4 line items that reference Table 3.5-1, item 3.5.1-51, the applicant included a reference to Note E and credited the ASME Section XI, Subsection IWF Program for managing this aging effect or mechanism in an air – indoor environment for high-strength low alloy steel bolting with a yield strength greater than 150 ksi and having an intended function of structural support for Class 1 piping and components (high-strength bolting for NSSS component supports). The applicant also included plant-specific Notes 1 and 2. Plant-specific Note 1 states, "ASME Section XI, Subsection IWF is the applicable aging management program for this component."

Plant-specific Note 2 states:

> NSSS Class 1 component supports (reactor pressure vessel support) utilize high strength ASTM A490 bolts (actual yield strength could be greater than or equal to 150 ksi). The bolts are not subject to high-sustained preload stress, aggressive environment, and lubricants containing contaminants not approved for use. Additionally ASTM A490 bolts have high resistance to stress corrosion cracking due to their ductility and industry and plant specific operating experience have not identified stress corrosion cracking of ASTM A490 bolts as a concern. Therefore cracking due to stress corrosion cracking is not an aging effect requiring aging management. Loss of material is the only aging effect requiring aging management. They are monitored for loss of material due to corrosion and loss of preload by visual inspection using the ASME Section XI, Subsection IWF.

The staff reviewed the AMR results lines that reference Note E and plant-specific Notes 1 and 2. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M18, "Bolting Integrity," the applicant proposed using the ASME Section XI, Subsection IWF Program.

The LRA states that these components have the intended function of structural support and are examined using the ASME Section XI, Subsection IWF Program as the primary AMP. The staff's review of the ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.1.15. The staff finds the applicant's use of the ASME Section XI, Subsection IWF Program acceptable because: (1) the program performs periodic visual examinations of exposed surfaces of bolting used in supports for loss of material and for loss of preload by inspecting for missing, detached, or loosened bolts and nuts, including monitoring for loss of material due to general corrosion of high-strength bolts (actual yield strength greater than 150 ksi); (2) the bolts are in an air – indoor noncorrosive environment; (3) the bolts are not preloaded to a high stress level; and (4) the program incorporates procedures based on EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide," to ensure proper specification of bolting material, lubricant, and installation torque. The staff finds that the applicant addressed the AERM adequately.

In the LRA Table 3.5.2-7 line items that reference Table 3.3-1, item 3.3.1-58, the applicant included a reference to Note E and credited the Structures Monitoring Program for managing this aging effect or mechanism in an air – indoor environment. The applicant also included plant-specific Note 3 which states, "[The] Structures Monitoring Program is the applicable aging management program for this component."

The staff reviewed the AMR results lines that reference Note E and plant-specific Note 1. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.M36, "External Surfaces Monitoring," the applicant proposed using the Structures Monitoring Program.

The LRA states that these components have the intended function of structural support and are examined using the Structures Monitoring Program as the primary AMP. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. GALL AMP XI.M36 is based on system visual inspections and walkdowns that are conducted periodically to identify loss of material due to general corrosion on the external surfaces of accessible steel components. The staff finds the applicant's use of the Structures Monitoring Program acceptable because the program: (1) performs visual inspections to monitor for indications of degradation such as loss of material and (2) has been enhanced to conduct the visual inspections on a frequency not to exceed 5 years. The staff finds that the applicant addressed the AERM adequately.

3.5.2.1.4 Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling) Due to Corrosion of Embedded Steel

In the LRA Table 3.3.2-10 line items that reference Table 3.5-1, item 3.5.1-23, the applicant included a reference to Note E and credited the Fire Protection Program for managing this aging effect or mechanism in an air – outdoor environment. The applicant also included plant-specific Note 6 which states, "The Fire Protection aging management program will be used in addition to the Structures Monitoring Program."

The staff reviewed the AMR results lines that reference Note E and plant-specific Note 6. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, "Structures Monitoring," the applicant proposed using the Fire Protection Program in addition to the Structures Monitoring Program.

The LRA states that these components have the intended function of fire barriers (masonry walls; interior) and are examined using the Structures Monitoring Program in addition to the Fire Protection Program as the AMPs. The staff's reviews of the Structures Monitoring and Fire Protection programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.7, respectively. The staff finds the applicant's use of the Fire Protection and Structures Monitoring programs acceptable because: (1) the Fire Protection Program has been enhanced to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling, and loss of material; (2) the masonry walls are also inspected under the Structures Monitoring Program that implements the Masonry Wall Program, which has been enhanced to add an examination checklist for masonry wall inspection requirements; and (3) the masonry wall inspections are conducted at a frequency of 5 years. The staff finds that the applicant addressed the AERM adequately.

In its response to RAI 3.3.1.65-01 dated July 19, 2010, the applicant stated that it identified a line item crediting the Fire Protection Program for the fire barriers (walls, ceilings, and floors) component type, which was inadvertently omitted from Table 3.3.2-10 for the fire protection system. The addition of the Fire Protection Program to manage the effects of aging for this component type in an air – indoor environment meets the GALL Report recommended inspection frequency for reinforced concrete fire barriers. LRA Table 3.3.2-10 was revised by the applicant to add the Fire Protection Program and align the line item to reference Table 3.5-1, item 3.5.1-23. The applicant also included plant-specific Note 6 which states, “The Fire Protection aging management program will be used in addition to the Structures Monitoring Program.”

The staff reviewed the AMR results lines that reference Note E and plant-specific Note 6. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, “Structures Monitoring,” the applicant proposed using the Fire Protection Program in addition to the Structures Monitoring Program.

The LRA states that these components have the intended function of fire barriers (masonry walls; interior) and are examined using the Structures Monitoring Program in addition to the Fire Protection Program as the AMPs. The staff’s reviews of the Structures Monitoring and Fire Protection programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.7, respectively. The staff finds the applicant’s use of the Fire Protection and Structures Monitoring programs acceptable because: (1) the Fire Protection Program has been enhanced to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling, and loss of material; (2) the masonry walls are also inspected under the Structures Monitoring Program that implements the Masonry Wall Program, which has been enhanced to add an examination checklist for masonry wall inspection requirements; and (3) the masonry wall inspections are conducted at a frequency of 5 years. The staff finds that the applicant addressed the AERM adequately.

3.5.2.1.5 Cracks and Distortion Due to Increased Stress Levels from Settlement

In the LRA Table 3.3.2-10 line items that reference Table 3.5-1 item 3.5.1-28, the applicant included a reference to Note E and credited the Fire Protection Program for managing this aging effect or mechanism in an air – outdoor environment. The applicant also included plant-specific Note 6 which states, “The Fire Protection aging management program will be used in addition to the Structures Monitoring Program.”

The staff reviewed the AMR results lines that reference Note E and plant-specific Note 6. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, “Structures Monitoring,” the applicant has proposed using the Fire Protection Program in addition to the Structures Monitoring Program.

The LRA states that these components have the intended function of fire barriers (masonry walls; interior) and are examined using the Structures Monitoring Program in addition to the Fire Protection Program as the AMPs. The staff’s reviews of the Structures Monitoring and Fire Protection programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.7, respectively. The staff finds the applicant’s use of the Fire Protection and Structures Monitoring programs acceptable because: (1) the Fire Protection Program has been enhanced to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling, and loss of material; (2) the masonry walls are also inspected under the Structures Monitoring Program that implements the Masonry Wall Program, which has been enhanced to add an examination checklist for masonry wall inspection requirements; and (3) the masonry wall inspections are conducted at a frequency of 5 years. The staff finds that the applicant addressed the AERM adequately.

3.5.2.1.6 Cracking Due to Restraint, Shrinkage, Creep, and Aggressive Environment

In the LRA Table 3.3.2-10 line items that reference Table 3.5.1, item 3.5.1-43, the applicant included a reference to Note E and credited the Fire Protection Program for managing this aging effect or mechanism in an air – indoor environment. The applicant also included plant-specific Note 6 which states, “The Fire Protection aging management program will be used in addition to the Structures Monitoring Program.”

The staff reviewed the AMR results lines that reference Note E and plant-specific Note 6. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S5, “Masonry Wall,” the applicant proposed using the Fire Protection Program in addition to the Structures Monitoring Program.

The LRA states that these components have the intended function of fire barriers (concrete block) and are examined using the Structures Monitoring Program in addition to the Fire Protection Program as the AMPs. The staff’s reviews of the Structures Monitoring and Fire Protection programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.7, respectively. The staff finds the applicant’s use of the Fire Protection and Structures Monitoring programs acceptable because: (1) the Fire Protection Program has been enhanced to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling, and loss of material; (2) the masonry walls are also inspected under the Structures Monitoring Program that implements the Masonry Wall Program, which has been enhanced to add an examination checklist for masonry wall inspection requirements; and (3) the masonry wall inspections are conducted at a frequency of 5 years. The staff finds that the applicant addressed the AERM adequately.

3.5.2.1.7 Cracking Due to Loss of Bond, Loss of Material (Spalling, Scaling)/Corrosion of Embedded Steel, Increase in Porosity and Permeability, Aggressive Chemical Attack, and Loss of Material Due to Abrasion and Cavitation

In the LRA Table 3.3.2-27 line items that reference Table 3.5-1 items 3.5.1-31 and 3.5.1-34, the applicant included a reference to Note E and credited the Buried Non-Steel Piping Inspection Program for managing these aging effects or mechanisms in a groundwater or soil (external) environment. The applicant also included plant-specific Note 7 which states, “The Open-Cycle Cooling Water System aging management program activities are adequate for managing the aging effects of the internal surfaces of reinforced concrete service water piping. The Buried Non-Steel Piping Inspection aging management program activities are adequate for managing the aging effects of the external surfaces of reinforced concrete service water piping.”

The staff reviewed the AMR results lines that reference Note E and plant-specific Note 7. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S6, “Structures Monitoring,” and GALL AMP XI.S7, RG 1.127, “Inspection of

Water-Control Structures Associated with Nuclear Power Plants," the applicant proposed using the Buried Non-Steel Piping Program.

The LRA states that these reinforced concrete piping and fitting components have the intended function of pressure boundary and are examined using the Buried Non-Steel Piping Program. The staff's review of the Buried Non-Steel Piping Program is documented in SER Section 3.0.3.3.4. Given that there have been a number of recent industry events involving leakage from buried or underground piping, the staff needs further information to evaluate the impact that these recent industry events might have on the applicant's Buried Non-Steel Piping Program. By letter dated August 6, 2010, the staff issued RAI B.2.1.24 requesting that the applicant provide information regarding how HCGS will incorporate the recent industry operating experience into its AMRs and AMPs. Pending the applicant's response to, and staff's review of, the aforementioned RAI, the staff is not able to confirm that the Buried Piping Inspection Program is suitably informed by the recent relevant operating experience.

In the LRA Table 3.3.2-27 line items that reference Table 3.5-1, items 3.5.1-37 and 3.5.1-45, the applicant included a reference to Note E and credited the Open-Cycle Cooling Water System Program for managing these aging effects or mechanisms in a raw water (internal) environment. The applicant also included plant-specific Note 7 which states, "The Open-Cycle Cooling Water System aging management program activities are adequate for managing the aging effects of the internal surfaces of reinforced concrete service water piping. The Buried Non-Steel Piping Inspection aging management program activities are adequate for managing the aging effects of the external surfaces of reinforced concrete service water piping."

The staff reviewed the AMR results lines that reference Note E and plant-specific Note 7. The staff determined, for these items, that the material, aging effect, and environment are consistent with the corresponding line of the GALL Report; however, where the GALL Report recommends GALL AMP XI.S7, RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," the applicant proposed using the Open-Cycle Cooling Water System Program.

The LRA states that these reinforced concrete piping and fitting components have the intended function of pressure boundary and are examined using the Open-Cycle Cooling Water System Program. The staff's review of the Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.1.9. Since the Open-Cycle Cooling Water System Program includes mitigative, performance-monitoring, and condition monitoring activities to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the open-cycle cooling water system, it is unclear to the staff that this is an adequate approach to managing aging of reinforced concrete piping and fitting components subjected to a raw water (internal) environment. By letter dated June 7, 2010, the staff issued RAI 3.5.2.1-6 requesting that the applicant discuss how the Open-Cycle Cooling Water System Program will adequately address the AERMs.

By letter dated June 29, 2010, the applicant responded and explained that the Open-Cycle Cooling Water Program is the appropriate program to manage aging of the internal surfaces of the concrete piping because it implements inspections of the internal surfaces. The applicant explained that the concrete piping has a polymer coating applied to the interior surface of the pipe and that the interior of each piping header is visually inspected every other refueling outage (approximately every 3 years) for signs of coating and concrete degradation.

The staff reviewed the applicant's response and found it acceptable because it explained that visual inspections are conducted on the internal surfaces of the concrete piping every other refueling outage. Visual inspections of the piping header will detect indications of age-related degradation in the piping and the header should be representative of the main piping. The type and frequency of the inspections are appropriate based on guidance provided by other GALL Report programs which manage aging of concrete, such as the Structures Monitoring Program. These programs suggest visual inspections with a frequency of at least every 5 years to detect degradation of concrete exposed to raw water. Based on its review of the applicant's response, the staff finds that the applicant addressed the AERM adequately and the staff's concern in RAI 3.5.2.1-6 is resolved.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.1.8 No Aging Effects That Requires Aging Management

In LRA Table 3.5-1, item 3.5.1-58, the applicant stated that the galvanized steel and aluminum support members, welds, bolted connections, and support anchorages to building structures exposed to indoor air for the material and environment combination do not have AERMs. The applicant also stated that no AMPs are applicable to the aluminum items exposed to indoor air for the electrical commodities system associated with this item number. The GALL Report, item III.B5-2 which corresponds to Table 3.5.1, item 3.5.1-58 recommends no AMP for this component group and, therefore, the staff finds the applicant's determination acceptable.

3.5.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

In LRA Section 3.5.2, the applicant further evaluated aging management, as recommended by the GALL Report, for the containments, structures, and component supports components and provides information concerning how it will manage aging effects in the following three areas:

(1) PWR and BWR containments:

- aging of inaccessible concrete areas
- cracks and distortion due to increased stress levels from settlement; reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations if not covered by the Structures Monitoring Program
- reduction of strength and modulus of concrete structures due to elevated temperature
- loss of material due to general, pitting, and crevice corrosion
- loss of prestress due to relaxation, shrinkage, creep, and elevated temperature
- cumulative fatigue damage
- cracking due to SCC
- cracking due to cyclic loading

- loss of material (scaling, cracking, and spalling) due to freeze-thaw
- cracking due to expansion and reaction with aggregate and increase in porosity and permeability due to leaching of calcium hydroxide

(2) safety-related and other structures and component supports:

- aging of structures not covered by the Structures Monitoring Program
- aging management of inaccessible areas (below-grade inaccessible concrete areas of Groups 1-5 and 7-9 structures)
- reduction of strength and modulus of concrete structures due to elevated temperature for Group 1-5 structures
- aging management of inaccessible areas for Group 6 structures (below-grade inaccessible concrete areas)
- cracking due to SCC and loss of material due to pitting and crevice corrosion for Groups 7 and 8 stainless steel tank liners
- aging of supports not covered by the Structures Monitoring Program
- cumulative fatigue damage due to cyclic loading

(3) QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff reviewed the applicant's evaluation to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.5.2.2. The staff's review of the applicant's further evaluation follows.

3.5.2.2.1 Pressurized Water Reactor and Boiling Water Reactor Containments

The staff reviewed LRA Section 3.5.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.1, which addresses several areas:

Aging of Inaccessible Concrete Areas. LRA Section 3.5.2.2.1.1 addresses aging of inaccessible concrete areas. In the LRA, the applicant stated that this item is not applicable to the HCGS Mark I steel containment. The containment is located in a reactor building and is subject to an indoor, non-aggressive environment. The containment is supported by foundation concrete of the reactor building, but the reactor building foundation concrete does not perform a pressure retaining function and, therefore, is not subject to ASME Code Section XI, Subsection IWL inspections.

The staff reviewed LRA Section 3.5.2.2.1.1 against the criteria in SRP-LR Section 3.5.2.2.1.1, which states that increases in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack, and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel could occur in inaccessible areas of PWR and BWR concrete and steel containments. The GALL Report identifies ASME Section XI, Subsection IWL to manage these aging effects and recommends further evaluation of plant-specific programs to manage these aging effects for inaccessible areas if the environment is aggressive.

The staff confirmed that HCGS uses a Mark I steel containment and is located in the reactor building. The steel containment is supported by the concrete foundation of the reactor building. The concrete foundation of the reactor building does not perform a pressure retaining function and settlement of the reactor building foundation is managed by the Structures Monitoring Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds the applicant's evaluation of this AERM acceptable. SER Section 3.5.2.2.2, "Aging Management of Inaccessible Areas," documents the staff's review of the applicant's evaluation of aging management of inaccessible areas, including the reactor building.

LRA Section 3.5.2.2.1.1 addresses aging of inaccessible concrete areas in PWR and BWR containments. The applicant stated that its primary containment is a Mark I steel containment and that item 3.5.1-1 in LRA Table 3.5.1 is not applicable to the Mark I steel containment design. In item 3.5.1-1, the applicant also stated that inaccessible concrete areas of the reactor building are addressed by items 3.5.1-31 and 3.5.1-23 which credit the Structures Monitoring Program for aging management.

The staff confirmed that no AMR results lines in LRA Tables 3.5.2-1 through 3.5.2-13, which include both the primary containment and the reactor building (secondary containment), are referenced to LRA Table 3.5.1, item 3.5.1-1. The staff also confirmed that the UFSAR supplement describes the applicant's primary containment as a Mark I steel containment design and that concrete is not applicable for this containment design. On the basis that the applicant has a steel containment design for which concrete is not applicable and other concrete elements associated with item 3.5.1-1 are included in items 3.5.1-31 and 3.5.1-23, the staff finds the applicant's determination that item 3.5.1-1 is not applicable to be acceptable.

<u>Cracks and Distortion Due to Increased Stress Levels from Settlement; Reduction of Foundation Strength, Cracking and Differential Settlement Due to Erosion of Porous Concrete Subfoundations, if Not Covered by the Structures Monitoring Program</u>. LRA Section 3.5.2.2.1.2 refers to Table 3.5.1, items 3.5.1-2 and 3.5.1-3 and addresses cracks and distortion due to increased stress levels from settlement; and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations, if not covered by the Structures Monitoring Program. In the LRA, the applicant stated that the Mark I steel containment is supported by the reactor building foundation concrete and the foundation concrete does not incorporate either a porous concrete subfoundation or a dewatering system.

The staff reviewed LRA Section 3.5.2.2.1.2 against the criteria in SRP-LR Section 3.5.2.2.1.2, which states that cracks and distortion due to increased stress levels from settlement; and reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations could occur. The GALL Report identifies the structures monitoring program to manage these aging effects and no further evaluation is recommended if this activity is within scope of the Structures Monitoring Program.

The staff confirmed that HCGS uses a Mark I steel containment and is located in the reactor building and is supported by the concrete foundation of the reactor building. The LRA states that cracks and distortion due to increased stress levels from settlement of the reactor building foundation are managed by the Structures Monitoring Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff also confirmed that the HCGS reactor building foundation does not have either a porous concrete subfoundation or a dewatering system. The staff finds acceptable the applicant's evaluation of this AERM in that the criteria in SRP-LR Section 3.5.2.2.1.2 are met.

<u>Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature</u>. LRA Section 3.5.2.2.1.3 refers to Table 3.5.1, item 3.5.1-4 and addresses reduction of strength and modulus of concrete structures due to elevated temperature. In the LRA, the applicant stated that item 3.5.1-4 is not applicable at HCGS. The LRA states that air is circulated by the drywell air cooling system that limits the bulk air temperature inside the drywell during normal plant operation to 135 °F, with a maximum local air temperature of 194 °F above elevation 162 feet. Concrete structural components in the drywell are not subject to general area temperatures greater than 150 °F or local area temperatures greater than 200 °F. The LRA further states that process piping penetrations having temperatures greater than 200 °F are insulated through the penetrations and when combined with compartment air circulation, the concrete local area temperatures are reduced to less than 200 °F.

The staff reviewed LRA Section 3.5.2.2.1.3 against the criteria in SRP-LR Section 3.5.2.2.1.3, which recommends further evaluation of the plant-specific AMP if any portion of the concrete containment components exceeds the specified temperature limits of 66 C (150 °F) general and 93 °C (200 °F) local.

The staff finds acceptable the applicant's evaluation that this aging effect is not applicable because HCGS uses a Mark I steel containment and no concrete performs a pressure retaining function. SER Section 3.5.2.2.2, "Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature," documents the staff's review of the applicant's evaluation of aging management of reduction of strength and modulus of other in-scope concrete structures due to elevated temperature.

<u>Loss of Material Due to General, Pitting, and Crevice Corrosion</u>. LRA Section 3.5.2.2.1.4 refers to Table 3.5.1, item 3.5.1-5 and addresses loss of material due to general, pitting, and crevice corrosion for steel elements of accessible and inaccessible areas of containments. In the LRA, the applicant stated that the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs will be used to manage aging of accessible and inaccessible areas of the BWR Mark I primary containment pressure retaining components due to general, pitting, and crevice corrosion. In the LRA, the applicant further stated that accessible areas are subject to periodic examinations to detect loss of material due to general, pitting, and crevice corrosion. Inaccessible areas are examined when they become accessible, or if they are suspected of degradation based on examination of the corresponding accessible area. The concrete in contact with the embedded drywell shell and the drywell support skirts meets the specifications of ACI 318-71 and the guidance of ACI 201.2R.

The applicant also stated that accessible portions of the drywell floor concrete are monitored under the Structures Monitoring Program to ensure that it is free of penetrating cracks that provide a path for water seepage to the surface of the embedded drywell shell. Water ponding on the containment drywell concrete floor is not common and when detected, is cleaned up in a timely manner. The applicant also stated that the current HCGS design does not require installation of a moisture barrier at the junction where the inner drywell shell becomes embedded in concrete. Visual inspection of this interface did not identify gaps, cracks, or separation of concrete from the drywell shell that would be a path for potential water leakage intrusion into the embedded shell. Visual examination conducted in accordance with ASME Code Section XI, Subsection IWE did not identify significant corrosion at the interface. The examiners noted only local surface rust in areas where the drywell shell coating is chipped or damaged as a result of maintenance activities. There were no indications that corrosion is occurring in the drywell shell below the concrete floor.

The applicant further explained that in 2007 and 2009, HCGS conducted UT measurements of the drywell shell thickness at sample locations above the junction of where the shell becomes embedded in concrete. This area was reported in IN 2004-01 as susceptible to loss of material due to corrosion. Also, measurements in this area would detect significant loss of material that could be occurring in inaccessible exterior surfaces of the drywell shell, specifically in the "sand-pocket region." There is no "sand-pocket region" or sand in the concrete foundation transition zone of the drywell shell and the air gap at HCGS. UT measurement results showed that, in each case, the measured thickness was greater than the specified nominal drywell shell thickness. The minimum measured thickness was 1.51 inches as compared to the nominal design thickness of 1.5 inches. However, the applicant explained that during the 2009 refueling outage, water was found trickling out of a reactor building concrete wall penetration sleeve from the drywell air gap region and ponded on the torus room floor. Analysis of the ponded water identified it as reactor water and refueling water. A review of past UT readings on the upper region, taken in 2007, of the drywell shell in areas of reported water leakage indicates no loss of material of the drywell shell. The water leakage stopped after the refueling cavity was drained at the end of the refueling outage. The suspected source of the water was the refuel bellow or liner. The air gap drains were inspected and there was no blockage or standing water in the air gap region, and the drywell shell showed no signs of corrosion. The water leakage issue was entered into the corrective action program to determine the cause of the leakage and corrective actions to prevent reoccurrence. In 2007, HCGS also conducted UT measurements of the drywell shell thickness at sample locations in the upper region of the drywell. Areas subject to UT examination include locations where two plates of different thicknesses are welded together to form the drywell shell. The condition of the drywell shell at the interface of the two plates has been of interest to the staff because of the likelihood of moisture collection at the ledge that may be formed by the thicker of the two plates. UT measurement results showed that, in each case, the measured thickness was greater than the specified nominal drywell shell thickness.

By letter dated May 14, 2010, the staff issued RAI B.2.1.28-01 requesting that the applicant discuss: (1) plans for determining the root cause of the water leak, (2) why the water did not exit through the drywell lower air gap drains, (3) plans for performing NDE of the drywell area potentially affected to demonstrate that water is not trapped in the annular space between the concrete shield wall and drywell, and (4) plans to quantify the effects of water leakage on the drywell including volumetric examination and a detailed engineering analysis. This issue, including the RAI response and the staff's review, is discussed in detail in the ASME Section XI, Subsection IWE Program write-up in SER Section 3.0.3.2.14.

During the October 2010 outage, the applicant again observed leakage from the same penetration sleeve J13, as well as from penetration sleeve J14. By letter dated January 3, 2011, the staff issued RAI B.2.1.28-3 requesting additional information regarding how the applicant will address this new plant-specific operating experience.

By letter dated January 19, 2011, the applicant responded and explained that during the October 2010 outage, additional boroscope inspections had been conducted on the air gap drains which revealed covers on the drains. These covers prevented the boroscope from accessing the air gap and may prevent proper drainage of the drywell air gap. The applicant further explained that this condition has been entered into the corrective action program, with actions to restore drain line functionality prior to flood-up of the reactor cavity during the next refueling outage. The applicant also stated in the response, that during the October 2010 outage, boroscope inspections of the drywell air gap were conducted through the penetration sleeves at the J13, J14, J19, J24, and J37 penetrations, which are all in close proximity to the J13 penetration. The applicant stated that these inspections confirmed that there are no obstructions in the air gap around the penetrations that could retain water against the drywell shell and that there are no visible signs of corrosion in this area.

In addition to the boroscope inspections, the applicant took UT thickness measurements of the drywell between the leaking penetrations and the floor. The measurements were all above nominal plate thickness except the area under the J13 penetration sleeve. This area had readings below the nominal plate thickness of 1.5 inch; however, the average reading was above the miniminum allowable manufacturing tolerance of 1.49 inches, and the individual readings were all above the 1.4375-inch thickness used in the design analysis. To address this area of possible degredation, the applicant will take UT measurements at the same locations during the next three refueling outages. The applicant stated that if the future measurements indicate ongoing corrosion, a corrosion rate will be determined and the issue will be entered into the corrective action program.

Subsequently, during a May 9, 2011, telephone conference call, the applicant informed the staff that its further investigation of one of the drywell air gap drain lines indicated that the location of the blockage (where covers was installed) did not coincide with the drain line’s entrance into the air gap. The applicant was unable to identify through boroscope inspection from the air gap side, and opening that coincide with the drain line. Due to the level of exposure involved in performing such inspections, the applicant was not able to perform the same investigation for the remaining three drain lines for the air gap.

The staff was concerned about this new finding and requested the applicant to to describe in detail the existing configuarion of the air gap blocked drains, its impact on the applicant’s plans to clear these drain by the spring of 2012, and any revisions to the the enhancements and commitment 28 for the ASME Section XI, Subsection IWE Program. The applicant responded to this request by letter dated May 19, 2011, and provided information about the drywell air gap drain line configuaration, revised enhancements and commitment. Detailed information about this issue, including the staff’s review and acceptance of the enhancements, can be found in the ASME Section XI, Subsection IWE Program evaluation in SER Section 3.0.3.2.14.

Furthermore, the applicant stated that implementation of the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs, supplemented by the plant-specific activities described in SER Section 3.0.3.2.14, provide reasonable assurance that loss of material due to corrosion of the drywell shell will be adequately managed during the period of extended operation such that the intended functions of the Mark I containment drywell are maintained consistent with the CLB. Miscellaneous steel components (catwalks, stairs, handrails, ladders, platforms, etc.) inside the primary containment suppression chamber aligned to this line item based on material, environment, and aging effect, do not perform a primary containment intended function. The components are, therefore, not within the scope of the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs. The Structures Monitoring Program will be substituted to manage loss of material due to general, pitting, and crevice corrosion of these components.

The staff reviewed LRA Section 3.5.2.2.1.4 against the criteria in SRP-LR Section 3.5.2.2.1.4, which states that loss of material due to general, pitting, and crevice corrosion could occur in steel elements of accessible and inaccessible areas for all types of PWR and BWR containments. The existing program relies on ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J to manage this aging effect. The GALL Report recommends further evaluation of plant-specific programs to manage this aging effect for inaccessible areas if corrosion is significant. GALL Report item II.B1.1-2 states that for inaccessible areas (embedded steel shell or liner) loss of material due to corrosion is not significant if the following four conditions are satisfied:

(1) Concrete meeting the specifications of ACI 318 or 349 and the guidance of ACI 201.2R was used for the containment concrete in contact with the embedded containment shell or liner.

(2) The concrete is monitored to ensure that it is free of penetrating cracks that provide a path for water seepage to the surface of the containment shell or liner.

(3) The moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Code Section XI, Subsection IWE requirements.

(4) Water ponding on the containment concrete floor is not common and when detected, is cleaned up in a timely manner.

The staff's reviews of the applicant's Structures Monitoring; ASME Section XI, Subsection IWE; and 10 CFR Part 50, Appendix J programs are documented in SER Sections 3.0.3.2.16, 3.0.3.2.14, and 3.0.3.1.16, respectively. The staff reviewed the programs and verified that the above criteria were adequately addressed by the applicant and that plant-specific operating experience (i.e., leakage from the penetrations) is being addressed appropriately.

Based on the staff's review, including resolution to RAI B.2.1.28-1 and RAI B.2.1.28-3 as discussed above and in SER Section 3.0.3.2.14, the staff finds the applicant's evaluation acceptable because it addresses the guidance in LR-ISG-2006-01, the guidance in the SRP-LR, and the plant-specific water leakage detected during the 2009 and 2010 refueling outage.

<u>Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature</u>. LRA Section 3.5.2.2.1.5 refers to Table 3.5.1, item 3.5.1-7 and addresses loss of prestress due to relaxation, shrinkage, creep, and elevated temperature. In the LRA, the applicant stated that loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for the HCGS containment structure is not applicable since the HCGS containment structure does not use a prestressed concrete containment design.

The staff finds acceptable the applicant's evaluation that this aging effect is not applicable on the basis that the HCGS containment is a Mark I steel containment with no post-tensioned concrete.

<u>Cumulative Fatigue Damage</u>. LRA Section 3.5.2.2.1.6 refers to Table 3.5.1, items 3.5.1-8 and 3.5.1-9 and addresses cumulative fatigue damage. In the LRA, the applicant stated that at HCGS, cumulative fatigue damage of the suppression chamber (torus) shell (including welded joints), and penetrations (including penetration sleeves, dissimilar metal welds, and penetration

bellows), vent header, vent line bellows, and downcomers is a TLAA as defined in 10 CFR 54.3. The TLAA is evaluated in accordance with 10 CFR 54.21(c).

The staff reviewed LRA Section 3.5.2.2.1.6 against the criteria in SRP-LR Section 3.5.2.2.1.6, which states that fatigue analyses of penetrations are TLAAs as defined in 10 CFR 54.3. The evaluation of this TLAA is addressed separately in Section 4.6.

Cracking Due to Stress-Corrosion Cracking. LRA Section 3.5.2.2.1.7 refers to Table 3.5.1, items 3.5.1-10 and 3.5.1-11 and addresses cracking due to SCC. In the LRA, the applicant stated that SCC is not an applicable aging mechanism for stainless steel penetration sleeves, penetration bellows, dissimilar metal welds, and stainless steel vent line bellows. The LRA states that these components are located in an air – indoor environment and not subject to conditions that promote SCC (i.e., lack of chloride or sulfate contaminants).

The staff reviewed LRA Section 3.5.2.2.1.7 against the criteria in SRP-LR Section 3.5.2.2.1.7, which states that cracking due to SCC of stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds could occur in all types of PWR and BWR containments. Cracking could also occur in stainless steel vent line bellows for BWR containments. The existing program relies on ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J to manage this aging effect. The GALL Report recommends further evaluation of additional appropriate examinations and evaluations implemented to detect these aging effects for stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds and stainless steel vent line bellows.

Since the containment environment at HCGS does not contain a significant presence of contaminants, the staff determines that additional inspections are not necessary. The existing programs will adequately manage aging during the period of extended operation, and the staff finds the applicant's evaluation of this aging effect acceptable.

Cracking Due to Cyclic Loading. LRA Section 3.5.2.2.1.8 refers to Table 3.5.1, items 3.5.1-12 and 3.5.1-13 and addresses cracking due to cyclic loading. In the LRA, the applicant stated that items 3.5.1-12 and 3.5.1-13 are not applicable to HCGS containment components: steel, stainless steel elements, dissimilar metal welds; penetration sleeves, penetration bellows; suppression pool shell and unbraced downcomers; torus; vent line; vent header; vent line bellows; and downcomers. The applicant also stated that a fatigue analysis exists in the CLB for the following containment components: steel, stainless steel elements, dissimilar metal welds; penetration sleeves, penetration bellows; suppression pool shell and unbraced downcomers; torus; vent line; vent header; vent line bellows; and downcomers. The LRA further states that expansion bellows not associated with the containment are located in the reactor building and yard structures and have a design specification requirement of 2,000 normal cycles. Evaluation of fatigue due to cyclic loading of these components shows that the projected number of cycles for 60 years is approximately 600 cycles, thus significant cracking of the bellows due to cyclic loading is not expected to occur during the period of extended operation. The LRA also states that plant operating experience has not identified cracking of bellows as a concern.

The staff reviewed LRA Section 3.5.2.2.1.8 against the criteria in SRP-LR Section 3.5.2.2.1.8, which states that cracking due to cyclic loading of suppression pool steel and stainless steel shells (including welded joints) and penetrations (including penetration sleeves, dissimilar metal welds, and penetration bellows) could occur for all types of PWR and BWR containments and BWR vent header, vent line bellows, and downcomers. The existing program relies on ASME

Section XI, Subsection IWE and 10 CFR Part 50, Appendix J to manage this aging effect. However, VT-3 visual inspection may not detect fine cracks. The GALL Report recommends further evaluation for detection of this aging effect.

On the basis of its review, the staff finds the applicant's evaluation of the aging effect "cracking due to cyclic loading" acceptable. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable because HCGS uses a Mark I steel containment component and a fatigue analysis exists in the CLB for these components, thus cracking due to cyclic loading is a TLAA that has been addressed in SER Sections 3.5.2.2.1 and 4.6 and are being addressed by items 3.5.1-8 and 3.5.1-9.

Loss of Material (Scaling, Cracking, and Spalling) Due to Freeze-Thaw. LRA Section 3.5.2.2.1.9 refers to Table 3.5.1, item 3.5.1-14 and addresses loss of material (scaling, cracking, and spalling) due to freeze-thaw. In the LRA, the applicant stated that this item is not applicable because HCGS has a BWR Mark I steel containment that is located in the reactor building. Repeated freeze-thaw is not applicable and, therefore, loss of concrete material and cracking will not occur.

The staff reviewed LRA Section 3.5.2.2.1.9 against the criteria in SRP-LR Section 3.5.2.2.1.9, which recommends further evaluation of loss of material due to freeze-thaw for plants with concrete containments located in moderate to severe weathering conditions.

The staff finds the applicant's evaluation acceptable that this aging effect is not applicable because HCGS has a Mark I steel containment and there is no ASME Code Section III, Division 2 Class CC concrete. Concrete that supports the Mark I steel containment is located in the reactor building and since it is not exposed to outdoor air, it will not be subjected to freeze-thaw cycles.

Cracking Due to Expansion and Reaction with Aggregate and Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide. LRA Section 3.5.2.2.1.10 refers to Table 3.5.1, item 3.5.1-15 and addresses cracking due to expansion and reaction with aggregate and increase in porosity and permeability due to leaching of calcium hydroxide. In the LRA, the applicant stated that this item is not applicable because HCGS has a BWR Mark I steel containment. The LRA also states that the HCGS containment-related reinforced concrete is designed and constructed to ACI and ASTM specifications that meet the intent of ACI 201.2R, and the containment-related concrete is not subjected to flowing water. Therefore, managing the effects of cracking due to expansion and reaction with aggregates, and increase in porosity and permeability due to leaching of calcium hydroxide is not required.

The staff reviewed LRA Section 3.5.2.2.1.10 against the criteria in SRP-LR Section 3.5.2.2.1.10, which states that cracking due to expansion and reaction with aggregate and increase in porosity and permeability due to leaching of calcium hydroxide could occur in concrete elements of concrete and steel containments. The GALL Report recommends further evaluation if the aggregate was not evaluated for potential expansion or reaction due to reactivity with the cementitious materials and suggests ASME Section XI, Subsection IWL as the AMP.

The staff confirmed that no HCGS containment concrete serves a pressure retaining function. Therefore, the concrete does not need to be evaluated in this section. SER Section 3.5.2.2.2, "Aging Management of Inaccessible Areas," documents the staff's review of the applicant's evaluation of cracking due to expansion and reaction with aggregate and increase in porosity and permeability due to leaching of calcium hydroxide. The staff confirmed that aggregate reaction aging effects for the concrete are managed by the Structures Monitoring Program, which conducts inspections by qualified personnel for indications of distress as defined by ACI 201.1R, and through enhancement, implements acceptance criteria specified in ACI 349.3R-96. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.1 criteria. For those line items that apply to LRA Section 3.5.2.2.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.2 Safety-Related and Other Structures and Component Supports

The staff reviewed LRA Section 3.5.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2, which addresses several areas as discussed below.

<u>Aging of Structures Not Covered by the Structures Monitoring Program</u>. In the LRA, the applicant stated that the Structures Monitoring Program is used to manage aging effects applicable to Groups 1, 3, and 4 structures, with Group 5, "Fuel Storage Facility," included with Group 1 structures. The applicant also stated that Groups 2, 7, 8, and 9 structures do not exist at HCGS and certain aging mechanisms identified in the GALL Report are not applicable to some Group 1, 3, and 4 structures. However, the applicant stated that accessible structures will be monitored for loss of material, cracking, increase in porosity and permeability, and loss of bond through the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.2.1, which states that the GALL Report recommends further evaluation of certain structure and aging effect combinations if they are not covered by the Structures Monitoring Program, including: (1) cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1-5, 7, and 9 structures; (2) increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack for Groups 1-5, 7, and 9 structures; (3) loss of material due to corrosion for Groups 1-5, 7, and 8 structures; (4) loss of material (spalling, scaling) and cracking due to freeze-thaw for Groups 1-3, 5, and 7-9 structures; (5) cracking due to expansion and reaction with aggregates for Groups 1-5 and 7-9 structures; (6) cracks and distortion due to increased stress levels from settlement for Groups 1-3 and 5-9 structures; and (7) reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation for Groups 1-3 and 5-9 structures. In addition, lock-up due to wear may occur for Lubrite® radial beam seats in BWR drywells, RPV support shoes for PWRs with nozzle supports, steam generator supports, and other sliding support bearings and sliding support surfaces. The existing program relies on the structures monitoring program or ASME Section XI, Subsection IWF to manage this aging effect. The GALL Report recommends further evaluation only for structure-aging effect combinations not within the ASME Section XI, Subsection IWF or Structures Monitoring Programs.

(1) Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling) Due to Corrosion of Embedded Steel for Groups 1-5, 7, and 9 Structures

LRA Section 3.5.2.2.2.1.1 refers to Table 3.5.1, item 3.5.1-23. In the LRA, the applicant stated that cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1 (includes Group 5 structures), 3, and 4 structures are monitored by the Structures Monitoring Program and thus further evaluation is not necessary.

The staff noted that Groups 1 (includes Group 5), 3, and 4 structures subject to this AERM are all in-scope of the Structures Monitoring Program. Therefore, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required.

(2) Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling) Due to Aggressive Chemical Attack for Groups 1-5, 7, and 9 Structures

LRA Section 3.5.2.2.2.1.2 refers to Table 3.5.1, item 3.5.1-24. In the LRA, the applicant stated that increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack of Groups 1 (includes Group 5 structures), 3, and 4 structures are not applicable to HCGS interior and above-grade exterior concrete because the structures are not exposed to aggressive chemical attack. The LRA also states that aging management of the Groups 1 (including Group 5 structures), 3, and 4 structures is done under the Structures Monitoring Program.

The staff noted that Groups 1 (includes Group 5), 3, and 4 structures subject to this AMR are all in-scope of the Structures Monitoring Program. Therefore, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required.

(3) Loss of Material Due to Corrosion for Groups 1-5, 7, and 8 Structures

LRA Section 3.5.2.2.2.1.3 refers to Table 3.5.1, item 3.5.1-25. In the LRA, the applicant stated that loss of material due to corrosion for Groups 1 (includes Group 5 structures), 3, and 4 structures and component supports is monitored through the Structures Monitoring Program, and thus a further evaluation is not necessary.

The staff noted that Groups 1 (includes Group 5), 3, and 4 structures subject to this AMR are all in-scope of the Structures Monitoring Program. Therefore, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required.

(4) Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-Thaw for Groups 1-5 and 7-9 Structures

LRA Section 3.5.2.2.2.1.4 refers to Table 3.5.1, item 3.5.1-26. In the LRA, the applicant stated that loss of material (spalling, scaling) and cracking due to freeze-thaw for Groups 1 (includes Group 5 structures), 3, and 4 structures are monitored through the Structures Monitoring Program and thus further evaluation is not necessary.

The staff noted that Groups 1 (including Group 5), 3, and 4 structures subject to this AMR are all in-scope of the Structures Monitoring Program. Therefore, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required.

(5) Cracking Due to Expansion and Reaction with Aggregates for Groups 1-5 and 7-9 Structures

LRA Section 3.5.2.2.2.1.5 refers to Table 3.5.1, item 3.5.1-27. In the LRA, the applicant stated that cracking due to reaction with aggregates for Groups 1 (includes Group 5 structures), 3, and 4 structures is not applicable as concrete specifications require the use of Type II, low-alkali cement. The LRA also stated that the aggregates were tested in conformance with ASTM C289 and C295 to demonstrate that the aggregate was not reactive. The LRA further states that the Structures Monitoring Program will be used to manage cracking of reinforced concrete in accessible areas of structures.

The staff noted that Groups 1 (includes Group 5), 3, and 4 structures subject to this AMR are all in-scope of the Structures Monitoring Program. Therefore, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required.

(6) Cracks and Distortion Due to Increased Stress Levels from Settlement for Groups 1-3 and 5-9 Structures

LRA Section 3.5.2.2.2.1.6 refers to Table 3.5.1, item 3.5.1-28. In the LRA, the applicant stated that the Structures Monitoring Program will be used to manage cracks and distortion due to increased stress levels from settlement of Groups 1 and 3 structures, however, this aging mechanism is insignificant at HCGS because the structures are founded on dense soil or the Vincentown Formation. The LRA also states that evaluation of pre-construction and post-construction soil explorations predicted the settlement to be no more than 1.5 inches for the safety-related structures and settlement leveled off soon after construction. The building foundations for the safety-related structures consist of reinforced concrete mats that bear on dense soil or the Vincentown Formation. Nonsafety-related building foundations consist of reinforced concrete slabs supported on piles. The LRA further states that a dewatering system and porous concrete subfoundations are not used at HCGS, and the structures are monitored under the Structures Monitoring Program.

The staff confirmed that Groups 1 and 3 structures subject to this AMR are all in-scope of the Structures Monitoring Program. Therefore, the staff finds that the criteria of SRP-LR Section 3.5.2.2.2.1 have been met and no further evaluation is required. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16.

(7) Reduction in Foundation Strength, Cracking, and Differential Settlement Due to Erosion of Porous Concrete Subfoundation for Groups 1-3 and 5-9 Structures

LRA Section 3.5.2.2.2.1.7 refers to Table 3.5.1, item 3.5.1-29. In the LRA, the applicant stated that Groups 1 and 3 structures are not subject to reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation because porous concrete subfoundations were not used at HCGS.

Based on the review of documents supporting the LRA, the staff agrees this aging affect is not applicable because HCGS has no porous concrete subfoundations.

(8) Lock-Up Due to Wear for Lubrite® Radial Beam Seats in BWR Drywell and Other Sliding Support Surfaces

LRA Section 3.5.2.2.2.1.8 refers to Table 3.5.1, item 3.5.1-30. In the LRA, the applicant stated that sliding surfaces are provided for supports for radial beam seats in the drywell, and the Structures Monitoring Program will be used to manage lock-up due to wear of these sliding surfaces.

The staff agrees that the Structures Monitoring Program is an appropriate AMP to manage lock-up due to wear of the sliding surfaces, however, during its review of this item, the staff was unable to verify that these sliding support surfaces were being inspected for loss of function due to corrosion, distortion, dirt, overload, or fatigue under either the Structures Monitoring or ASME Section XI, Subsection IWF programs. To address this, the staff issued RAI 3.5.2.2.2-1 by letter dated June 7, 2010, asking the applicant to explain if the inspections were being performed.

By letter dated June 29, 2010, the applicant responded and explained that the Lubrite® sliding surfaces are within the scope of the Structures Monitoring Program and they are visually inspected on a frequency of 5 years. The inspections look for evidence of corrosion, distortion, dirt, member misalignment, or other degraded conditions which would indicate loss of mechanical function.

The staff reviewed the applicant's response and found it acceptable because it verifies that the Lubrite® sliding supports are within the scope of the applicant's Structures Monitoring Program and they are subject to the appropriate visual inspections. The staff's concern in RAI 3.5.2.2.2-1 is resolved.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.2.1 criteria. For those line items that apply to LRA Section 3.5.2.2.2.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Aging Management of Inaccessible Areas. The staff reviewed LRA Section 3.5.2.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2.2, which states that the GALL Report recommends further evaluation of certain structure and aging effect combinations: (1) loss of material (spalling, scaling) and cracking due to freeze-thaw in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures for plants located in moderate to severe weathering conditions; (2) cracking due to expansion and reaction with aggregates in below-grade inaccessible concrete areas of Groups 1-5 and 7-9 structures if concrete was not constructed in accordance with recommendations in ACI 201.2R-77; (3) cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures for plants whose structures are not included within the scope of the applicant's Structures Monitoring Program; (4) increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack, and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures if the environment is aggressive; and (5) increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures if the concrete was not constructed in accordance with the recommendations in ACI 201.2R-77.

(1) Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures.

In the LRA, the applicant stated that Groups 1 and 3 structures are located in a region where weathering conditions are considered severe as shown in ASTM C33-90, Figure 1. GALL Report Groups 2, 7, 8, and 9 structures do not exist at HCGS. Concrete for Groups 1 and 3 structures is designed in accordance with ACI 318-71 and constructed in accordance with ACI 301-72. The HCGS concrete mixes were designed to provide for low permeability and adequate air entrainment (3 to 6 percent). The LRA also states that a review of operating experience did not identify significant loss of material and cracking due to freeze-thaw of reinforced concrete structures. The LRA further states that inaccessible reinforced concrete will be inspected, if excavated for any reason, as required by the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.2.2.1, which states that further evaluation is required for loss of material (spalling, scaling) and cracking due to freeze-thaw in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures for plants subjected to moderate to severe weathering conditions.

The staff noted that the GALL Report suggests existing concrete exposed to freeze-thaw have an air content of 3 to 6 percent. The air content recommended for concrete resistance to freezing and thawing by ACI 201.2R is 4.5 to 7.5 percent for severe exposure with a ±1.5 percent tolerance. The GALL Report also suggests a water-to-cement ratio between 0.35 and 0.45 for concrete exposed to potential freeze-thaw conditions. The staff noted that although an air content was specified for the concrete, a water-to-cement ratio was not provided as recommended in GALL Report item III.A3-6 for concrete located in moderate to severe weathering conditions. By letter dated June 7, 2010, the staff issued RAI 3.5.2.2.2-2 to address compliance of the HCGS concrete to recommendations provided in the GALL Report.

By letter dated June 29, 2010, the applicant responded and stated that the structural concrete mixes at HCGS included fly ash and had a water-to-cement ratio between 0.45 and 0.51. The applicant explained that although this ratio is outside the GALL Report recommended range, concrete inspections during the plant's operating history have not revealed degradation attributed to freeze-thaw. The applicant further explained that freeze-thaw damage generally occurs in areas accessible for inspection and any freeze-thaw degradation that may occur in the future will be detected in a timely manner by the 5-year frequency Structures Monitoring Program inspections.

The staff reviewed the applicant's response and noted that the applicant has no site-specific operating experience with concrete freeze-thaw degradation. In addition, the credited Structures Monitoring Program visual inspections provide assurance that any future degradation will be detected prior to a loss of intended function. Since the applicant does not have operating experience related to freeze-thaw degradation, the staff finds that the credited AMP is adequate to manage aging during the period of extended operation. The staff's concern in RAI 3.5.2.2.2-2 is resolved.

(2) Cracking due to expansion and reaction with aggregates could occur in below-grade inaccessible concrete areas for Groups 1-5 and 7-9 structures.

In the LRA, the applicant stated that at HCGS, the concrete portions of Groups 1 and 3 structures is not applicable as concrete specifications required the use of Type II, low-alkali cement conforming to ASTM C150, and the structures were designed in accordance with ACI 318-71 and constructed in accordance with ACI 301-72. The LRA also states that the aggregate was tested in accordance with ASTM C289 and ASTM C295 to demonstrate that the aggregate was not reactive as noted in ACI 201.2R. The LRA further states that inaccessible concrete, if excavated for any reason, will be inspected for cracking under the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2.2.2, which states that the GALL Report recommends further evaluation of inaccessible areas of these groups of structures if the concrete was not constructed in accordance with the recommendations in ACI 201.2R-77. GALL Report item III.A1-2 states that investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295-54 or ASTM C227-50 can demonstrate that the aggregate is not reactive within the reinforced concrete. If either of these conditions is met, the GALL Report notes that aging management is not necessary.

The staff found that the HCGS concrete mix design adequately addressed cracking due to expansion and reaction with aggregates. Concrete work was designed in accordance with ACI 318-713 and constructed in accordance with ACI 301-72. Type II, low-alkali content cement was used in the concrete mixes and aggregate materials were evaluated in accordance with ASTM C289 and ASTM C295 and found to be nonreactive. Therefore, cracking due to expansion and reaction with aggregate in below-grade inaccessible concrete areas for Groups 1 and 3 structures are not aging effects for concrete elements and no additional plant-specific program is required. Recommendations in the GALL Report and criteria in SRP-LR Section 3.5.2.2.2.2.2 have been met.

(3) Cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations could occur in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures.

In the LRA, the applicant stated that the Structures Monitoring Program will be used to manage cracks and distortion due to increased stress levels from settlement of Groups 1 and 3 structures, however, this aging mechanism is insignificant at HCGS. The building foundations for the safety-related structures consist of reinforced concrete mats that bear on dense soil or the Vincentown Formation. The LRA also states a review of operating experience has not identified significant signs of distress due to settlement and that since the magnitude of total settlement is small, the differential settlements are expected to be smaller. The LRA further states that the condition of accessible and above-grade concrete will be used as an indicator for the condition of the inaccessible and below-grade structural components and provides reasonable assurance that degradation will be detected before a loss of intended function. A dewatering system and porous concrete subfoundations are not used at HCGS.

The staff reviewed LRA Section 3.5.2.2.2.2.3 against the criteria in SRP-LR Section 3.5.2.2.2.2.3, which states that the GALL Report recommends verification of the continued functionality of the dewatering system during the period of extended operation if the plant’s CLB credits a dewatering system. The GALL Report recommends no further evaluation if this activity and these aging effects are included within the scope of the applicant’s Structures Monitoring Program.

On the basis of its review, the staff determined that cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations in below-grade inaccessible concrete areas of Groups 1 and 3 structures are not plausible aging effects due to the absence of these aging mechanisms. HCGS does not use a dewatering system, and there are no porous subfoundations on the site. In addition, the applicant monitors the above-grade exposed concrete for the aging effect of cracking or distortion due to settlement under the Structures Monitoring Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds that this program is consistent with the recommendations in the GALL Report and is adequate to manage cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement.

(4) Increase in porosity and permeability, cracking and loss of material (spalling, scaling) due to aggressive chemical attack, and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel could occur in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures.

LRA Section 3.5.2.2.2.2.4 refers to Table 3.5.1, item 3.5.1-31. In the LRA, the applicant stated that for Groups 1 and 3 structures at HCGS, the inaccessible below-grade reinforced concrete is subject to an aggressive environment. Groundwater and river water were sampled and tested in 2008 and 2009 and the test results revealed that although the pH and sulfate values meet the limits considered to be a non-aggressive environment according to the GALL Report, the test results for chlorides indicated an aggressive environment. The LRA also states that exposed portions of below-grade concrete will be examined by the Structures Monitoring Program when excavated for any reason, and groundwater chemistry will also be monitored periodically in accordance with the enhanced Structures Monitoring Program. Also, the periodic inspections of the submerged portions of the service water intake structure will be used as indicators for the condition of below-grade structures. The applicant further stated that due to groundwater chemistry being bounded by river water chemistry, the use of submerged structures as a leading indicator for the potential degradation of below-grade structures provides reasonable assurance that degradation of inaccessible structures will be detected before a loss of an intended function. In the event inspection of submerged structures identifies significant concrete degradations at the service water intake structure, corrective actions will be initiated to evaluate the condition of inaccessible portions of the Groups 1 and 3 structures and determine if excavation of concrete for inspection is warranted. The LRA also states that a review of operating experience has not identified significant signs of distress due to aggressive chemical attack or corrosion of embedded steel of submerged concrete components.

The staff reviewed LRA Section 3.5.2.2.2.2.4 against the criteria in SRP-LR Section 3.5.2.2.2.4, which states that the GALL Report recommends further evaluation of plant-specific programs to manage these aging effects or mechanisms in inaccessible areas of these groups of structures if the environment is aggressive. In the GALL Report, it is noted that for inaccessible areas of plants with non-aggressive groundwater or soil (i.e., pH greater than 5.5, chlorides less than 500 ppm, or sulfates less than 1,500 ppm), as a minimum the following should be considered: (1) examinations of the exposed portions of the below-grade concrete, when excavated for any reason; and (2) periodic monitoring of below-grade water chemistry, including consideration of potential seasonal variations. Since the applicant does not have definite plans for inspections of inaccessible areas and the groundwater is aggressive based on chloride values above the GALL Report limit, it is unclear to the staff that this is an adequate approach to managing aging of inaccessible concrete structures subjected to aggressive groundwater. In SER Section 3.0.3.2.16, “Structures Monitoring Program,” the staff issued RAI B.2.1.32-1 requesting that the applicant provide additional information to demonstrate that the current level of chlorides in the groundwater is not causing structural degradation of embedded walls or foundations. A more detailed discussion of the issue can be found in that section.

(5) Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide could occur in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures.

LRA Section 3.5.2.2.2.2.5 refers to Table 3.5.1, item 3.5.1-32. In the LRA, the applicant stated that leaching of calcium hydroxide is applicable for a flowing water environment that may occur to a limited extent in accessible or inaccessible portions of Groups 1 and 3 structures. The LRA also states that: (1) the HCGS concrete was designed and constructed to ACI and ASTM specifications that meet the intent of ACI 201.2R, (2) pozzolans were included in the concrete mixes to reduce its porosity and permeability, and (3) operating experience has found that increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide is not significant and is adequately managed by the Structures Monitoring Program. The LRA further states that exposed portions of the below-grade concrete will be examined when excavated for any purpose in accordance with the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.2.5 against the criteria in SRP-LR Section 3.5.2.2.2.2.5, which states that the GALL Report recommends further evaluation of this aging effect for inaccessible areas of Groups 1-3, 5 and 7-9 structures if concrete was not constructed in accordance with the recommendations in ACI 201.2R-77.

On the basis of its review, the staff finds that increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide in below-grade inaccessible concrete areas of Groups 1 and 3 structures is not a plausible AERM because the concrete structures were designed and constructed in accordance with ACI codes that enhance concrete’s resistance to leaching. In addition, exposed portions of the below-grade concrete will be examined when excavated for any purpose.

Based on the programs identified, the staff concludes that the applicant’s programs meet SRP-LR Section 3.5.2.2.2.2 criteria. For those line items that apply to LRA Section 3.5.2.2.2.2, the staff determines that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature. LRA Section 3.5.2.2.2.3 refers to Table 3.5.1, item 3.5.1-33. In the LRA, the applicant stated that this item is not applicable at HCGS. Groups 1 and 3 concrete structures are not subject to general area temperatures greater than 150 °F. Group 1 structures (reactor building) are subject to normal indoor temperatures not greater than 120 C and outdoor design temperatures of 94 °F. Group 3 structures are exposed to normal indoor air temperatures not greater than 115 °F. Group 4 structures are exposed to normal indoor temperatures inside the drywell with the bulk air temperature inside the drywell limited by the TS and UFSAR supplement to 135 °F during normal plant operation with a maximum local air temperature of 194 °F above elevation 162 feet. Group 5 structures (refuel floor and spent fuel storage pool) are part of the reactor building and are exposed to normal indoor air temperatures not greater than 104 °F. The LRA further states that the spent fuel pool temperature is maintained at a maximum of 135 °F under normal operating conditions. Groups 1, 3, and 4 concrete structural components are not subjected to temperatures greater than 200 °F with process piping operating at temperatures greater than 200 °F insulated where it passes through penetrations to reduce the concrete temperature to less than 200 °F. Plant operating experience has not identified general and local elevated temperature as a concern.

The staff reviewed LRA Section 3.5.2.2.2.3 against the criteria in SRP-LR Section 3.5.2.2.2.3, which states that reduction of strength and modulus of concrete due to elevated temperatures may occur in PWR and BWR Groups 1-5 concrete structures. ACI 349-85 specifies the concrete temperature limits for normal operation or any other long-term period and states that general area temperatures shall not exceed 65 C (150 °F) except for local areas that are permitted to have temperatures not to exceed 93 C (200 °F). The GALL Report recommends further evaluation of a plant-specific program if any portion of the safety-related and other concrete structures exceed these limits.

The staff noted that the LRA states that Groups 1, 3, 4, and 5 concrete elements do not exceed temperature limits associated with aging degradation due to elevated temperature (i.e., concrete general area temperatures are less than 150 °F and local area temperatures are less than 200 °F) and Group 2 structures do not exist at HCGS. On the basis of its review, the staff finds that reduction in strength and modulus of elasticity due to elevated temperatures in concrete areas of Groups 1, 3, 4, and 5 is not a plausible AERM because concrete temperatures are below limits specified in ACI 349-85. Therefore, the staff agrees that this is not an AERM for these components because the necessary condition does not exist; however, these areas will be inspected as noted in the Structures Monitoring Program.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.2.3 criteria. For those line items that apply to LRA Section 3.5.2.2.2.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Aging Management of Inaccessible Areas for Group 6 Structures. The staff reviewed LRA Section 3.5.2.2.2.4 against the criteria in SRP-LR Section 3.5.2.2.2.4.

(1) Increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack; and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel could occur in below-grade inaccessible concrete areas of Group 6 structures.

In the LRA, the applicant stated that the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program, as implemented through the Structures Monitoring Program, will be used to manage cracking, loss of bond, and loss of material due to corrosion of embedded steel in accessible above-grade and submerged areas of water-control structures (Group 6 structures). Inaccessible areas of Group 6 structures that are below-grade are subject to an aggressive groundwater environment. Exposed portions of below-grade concrete will be examined when excavated for any reason and groundwater chemistry will be monitored periodically in accordance with the Structures Monitoring Program. Also, the enhanced 5-year periodic inspections of the submerged portion of the service water intake structure will be used as indicators for the condition of below-grade portions of the structures. In the event inspection of submerged structures identifies significant concrete degradation at the service water intake structure, corrective actions will be initiated to evaluate the condition of inaccessible below-grade portions of the Group 6 structures and determine if excavation of concrete for inspection is warranted. The LRA further states that the Buried Non-Steel Piping Inspection Program will be substituted to manage this AERM for reinforced concrete piping and fittings of the service water intake structure.

The staff reviewed LRA Section 3.5.2.2.2.4.1 against the criteria in SRP-LR Section 3.5.2.2.2.4.1, which states that the GALL Report recommends further evaluation of plant-specific programs to manage these aging effects in inaccessible areas if the environment is aggressive.

The staff's review of these aging effects for inaccessible concrete elements of Groups 1 and 3 structures is documented in SER Section 3.5.2.2.2, "Aging Management of Inaccessible Areas." The staff noted that inspections of Group 6 structures are performed under the Structures Monitoring Program which is consistent with and integrates the elements of the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program. The staff's reviews of the Structures Monitoring and RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.17, respectively. The staff confirmed that Group 6 structures subject to this AMR are within the scope of the Structures Monitoring and RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" programs. Since the applicant does not have definite plans for inspections of inaccessible areas and the groundwater or river water is aggressive, it is unclear to the staff that this is an adequate approach to managing aging of inaccessible concrete structures subjected to aggressive groundwater or river water. In SER Section 3.0.3.2.16, "Structures Monitoring Program," the staff issued RAI B.2.1.32-1 requesting that the applicant provide additional information to demonstrate that the current level of chlorides in the groundwater is not causing structural degradation of embedded walls or foundations. A more detailed discussion of the issue can be found in that section.

Furthermore, the applicant stated that the Buried Non-Steel Piping Inspection Program will be substituted to manage this AERM for reinforced concrete piping and fittings through inspections of external surfaces. The staff's review of the Buried Non-Steel Piping Inspection Program is documented in SER Section 3.0.3.3.4. Since this program uses opportunistic and focused inspections and at least one opportunistic inspection will be performed within 10 years prior to entering the period of extended operation and at least one focused inspection will be performed within the first 10 years of extended operation, the staff finds that the applicant addressed the AERM adequately for the reinforced concrete piping and fittings of the service water intake structure.

(2) Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures.

LRA Section 3.5.2.2.2.4.2 refers to Table 3.5-1, item 3.5.1-35, and the applicant stated that the RG 1.127, Inspections of Water-Control Structures Associated with Nuclear Power Plants" Program, as implemented by the Structures Monitoring Program, will be used to manage loss of material (spalling, scaling) and cracking due to freeze-thaw in accessible areas of water-control structures (Group 6 structures). Group 6 structures are located in a region where weathering conditions are considered severe as shown in ASTM C33-90, Figure 1. The LRA also states that the concrete for Group 6 structures is designed in accordance with ACI 318-71 and constructed in accordance with ACI 301-72, and the concrete mixes were designed to provide for low permeability and adequate air entrainment (3 to 6 percent). The LRA further states that a review of operating experience did not identify significant loss of material and cracking due to freeze-thaw of reinforced concrete in Group 6 structures and that inaccessible reinforced concrete will be inspected, if excavated for any reason, as required by the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.4.2 against the criteria in SRP-LR Section 3.5.2.2.2.4.2, which states that the GALL Report recommends further evaluation of this aging effect for inaccessible areas for plants located in moderate to severe weathering conditions.

The staff's review for these aging effects for inaccessible concrete elements of Groups 1 and 3 structures is documented in SER Section 3.5.2.2.2.2.1. The staff noted that inspections of accessible Group 6 structures are performed under the Structures Monitoring Program which is consistent with and integrates the elements of the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program. The staff's reviews of the Structures Monitoring and RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.17, respectively. GALL Report item III.A6-5 suggests that aging management is not necessary if the existing concrete has an air content of 3 to 6 percent and a water-to-cement ratio between 0.35 and 0.45 for concrete exposed to potential freeze-thaw conditions. The staff noted that although an air content was specified for the concrete, a water-to-cement ratio was not provided for the HCGS concrete as specified in GALL Report item III.A6-5 for concrete located in moderate to severe weathering conditions. In SER Section 3.5.2.2.2, "Aging Management of Inaccessible Areas," the staff issued RAI 3.5.2.2.2-2 to address compliance of the HCGS concrete to recommendations provided in the GALL Report. A more detailed discussion of the staff's review of this issue can be found in that section.

(3) Cracking due to expansion and reaction with aggregates and increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide could occur in below-grade inaccessible reinforced concrete areas of Group 6 structures.

In the LRA, the applicant stated that cracking due to expansion or reaction with aggregates is not applicable for inaccessible areas of reinforced concrete of Group 6 structures because the aggregate materials were tested in accordance with ASTM C289 and C295 for potential reactivity and refers to Table 3.5.1, item 3.5.1-36.

The staff reviewed LRA Section 3.5.2.2.2.4.3 against the criteria in GALL Report item III.A6-2 which notes that, according to NUREG-1557, investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295-54 can demonstrate that these aggregates do not react within reinforced concrete. The staff's review for cracking due to expansion and reaction with aggregates for inaccessible concrete elements of Groups 1 and 3 structures is documented in SER Section 3.5.2.2.2.2.2. The staff noted that inspections of Group 6 structures are performed under the Structures Monitoring Program which is consistent with and integrates the elements of the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. Since the Group 6 structures subject to this AERM are within the scope of the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program and the aggregate materials have been tested to demonstrate that they are not reactive, the criteria of GALL Report item III.A6-2 have been met.

In the LRA, the applicant stated that the reinforced concrete for HCGS Group 6 structures was designed in accordance with ACI 318-71 and constructed in accordance with ACI 301-72 to meet the intent of ACI 201.2R and refers to Table 3.5.1, item 3.5.1-37. The LRA also states that increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide of reinforced concrete in accessible and inaccessible areas of water-control structures (Group 6 structures) subject to a flowing water environment will be managed by the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program, as implemented by the Structures Monitoring Program. Leaching is a potential aging mechanism applicable to submerged portions of Group 6 structures exposed to flowing water. However, these areas are accessible for inspections when dewatered and periodic inspections of the submerged reinforced concrete components will be used as a leading indicator for inaccessible concrete. Inaccessible concrete will be inspected when excavated for any reason, as required under the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.4.3 against criteria in SRP-LR Section 3.5.2.2.2.4.3, which states that the GALL Report recommends further evaluation of inaccessible areas of Group 6 structures for increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide if concrete was not constructed in accordance with the recommendations in ACI 201.2R-77. The staff's review for increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide for inaccessible concrete elements of Groups 1 and 3 structures is documented in SER Section 3.5.2.2.2, "Aging Management of Inaccessible Areas." The staff noted that inspections of Group 6 structures are performed under the Structures Monitoring Program which is consistent with and integrates the elements of the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. Since the Group 6 structures subject to this AERM are within the scope of the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program and the concrete was designed and constructed in accordance with requirements that meet the intent of ACI 201.2R, the criteria of GALL Report item III.A6-6 have been met.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.2.4 criteria. For those line items that apply to LRA Section 3.5.2.2.2.4, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Cracking Due to Stress-Corrosion Cracking and Loss of Material Due to Pitting and Crevice Corrosion. LRA Section 3.5.2.2.2.5 refers to Table 3.5.1, item 3.5.1-38. In the LRA, the applicant stated that HCGS does not have Group 7 and 8 stainless steel tank liners and further evaluation for the effects of cracking due to SCC and loss of material due to pitting and crevice corrosion is not applicable.

The staff reviewed LRA Section 3.5.2.2.2.5 against the criteria in SRP-LR Section 3.5.2.2.2.5, which states that cracking due to SCC and loss of material due to pitting and crevice corrosion could occur for Groups 7 and 8 stainless steel tank liners exposed to standing water. The GALL Report recommends further evaluation of plant-specific programs to manage these aging effects.

The staff noted that LRA Sections 3.5.2.2.2.1 and 3.5.2.2.2.5 state that Groups 7 and 8 structures, which refer to concrete tanks and missile barriers, and steel tanks and missile barriers, respectively, do not exist at HCGS. However, there are several tanks within the scope of license renewal so the staff does not understand how the statements in the LRA are accurate. To address this issue, the staff issued RAI 3.5.2.2.2-3 by letter dated June 25, 2010.

The applicant responded by letter dated July 20, 2010, and explained that no tanks with stainless steel liners exposed to standing water are within the scope of license renewal. Stainless steel and steel tanks that are within the scope of license renewal are addressed as components of the applicable mechanical system, not as Groups 7 or 8 structures. The applicant revised LRA Sections 3.5.2.2.2.1 and 3.5.2.2.2.5 and Table 3.5.1 to clarify this point. The applicant also explained that the skimmer surge tanks were aligned with item 3.3.1-24 which discusses loss of material of stainless steel components exposed to treated water. The GALL Report recommended programs for these components are water chemistry and one-time inspection. The applicant has credited both of these programs for aging management of the skimmer surge tanks. The applicant further explained that cracking due to SCC is not an applicable aging effect for the skimmer surge tanks because the fuel pool water temperature is below 140 °F.

The staff reviewed the applicant's response and finds it acceptable because it explained that the tanks within the scope of license renewal either are not exposed to standing water or aging is being managed as part of the applicable mechanical system. For the skimmer surge tank components, the staff finds the applicant's response acceptable because the water temperature remains below the threshold for SCC and the GALL Report recommended AMPs are being credited to manage loss of material due to pitting and crevice corrosion. The staff's concern in RAI 3.5.2.2.2-3 is resolved.

Aging of Supports not Covered by the Structures Monitoring Program. The staff reviewed LRA Section 3.5.2.2.2.6 against the criteria in SRP-LR Section 3.5.2.2.2.6.

(1) Loss of Material Due to General and Pitting Corrosion, for Groups B2-B5 Supports

LRA Section 3.5.2.2.2.6.1 refers to Table 3.5.1, item 3.5.1-39. In the LRA, the applicant stated that loss of material due to general and pitting corrosion for Groups B2-B5 supports is covered under the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.6.1 against the criteria in SRP-LR Section 3.5.2.2.2.6, which states that further evaluation is necessary only for structure and aging effect combinations not covered by the structures monitoring program.

The staff noted that the component support and aging effect combination of loss of material due to general and pitting corrosion for Groups B2-B5 supports is managed by the Structures Monitoring Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16.

(2) Reduction in Concrete Anchor Capacity Due to Degradation of the Surrounding Concrete for Groups B1-B5 Supports

LRA Section 3.5.2.2.2.6.2 refers to Table 3.5.1, item 3.5.1-40. In the LRA, the applicant stated that reduction in anchor capacity due to degradation of the surrounding concrete for Groups 1-5 supports is covered under the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.6.2 against the criteria in SRP-LR Section 3.5.2.2.2.6.2, which states that further evaluation is necessary only for structure and aging effect combinations not covered by the structures monitoring program.

The staff noted that the component support and aging effect combination of reduction in anchor capacity due to degradation of surrounding concrete for Groups 1-5 supports is managed by the Structures Monitoring Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16.

(3) Reduction Due to Loss of Isolation Function Due to Degradation of Vibration Isolation Elements for Group B4 Supports

LRA Section 3.5.2.2.2.6.3 refers to Table 3.5.1, item 3.5.1-41. In the LRA, the applicant stated that reduction due to loss of isolation function due to degradation of vibration isolation elements for Group B4 supports is covered under the Structures Monitoring Program.

The staff reviewed LRA Section 3.5.2.2.2.6.3 against the criteria in SRP-LR Section 3.5.2.2.2.6.3, which states that further evaluation is necessary only for structure and aging effect combinations not covered by the structures monitoring program.

The staff noted that the reduction due to loss of isolation function due to degradation of vibration isolation elements for Group B4 supports is managed by the Structures Monitoring Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.2.6 criteria. For those line items that apply to LRA Section 3.5.2.2.2.6, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Cumulative Fatigue Damage Due to Cyclic Loading</u>. LRA Section 3.5.2.2.2.7 refers to Table 3.5.1, item 3.5.1-42. In the LRA, the applicant stated that the CLB contains no fatigue analysis for component support members, anchor bolts, and welds of Groups B1.1, B1.2, and B1.3 component supports. Therefore, a TLAA is not evaluated in accordance with 10 CFR 54.21(c) for these components.

The staff reviewed LRA Section 3.5.2.2.2.7 against the criteria in SRP-LR Section 3.5.2.2.2.7, which states that fatigue of component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports is a TLAA as defined in 10 CFR 54.3 only if a CLB fatigue analysis exists. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed separately in Section 4.3, “Metal Fatigue Analysis,” of this SER.

The staff verified that at HCGS, the CLB contains no fatigue analysis for component support members, anchor bolts, and welds of Groups B1.1, B1.2, and B1.3 component supports. The staff’s evaluation of metal fatigue TLAA is documented in SER Section 4.0.

Based on the programs identified, the staff concludes that the applicant’s programs meet SRP-LR Section 3.5.2.2.2 criteria. For those line items that apply to LRA Section 3.5.2.2.2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.3 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff’s evaluation of the applicant’s QA program.

3.5.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.5.2-1 through 3.5.2-13, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.5.2-1 through 3.5.2-13, the applicant indicated, via Notes F through J that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant’s evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. The staff’s evaluation is documented in the following sections.

LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-3, 3.5.2-4, 3.5.2-8, 3.5.2-9, and 3.5.2-12 were revised as a result of the response to RAI B.2.1.12-01, dated June 14, 2010. The revision added AMR items in these tables to reference the applicant’s Bolting Integrity Program to manage the aging for bolting AMR items. Existing bolting AMR items which reference other AMPs are used in conjunction with the added bolting AMR items to properly manage aging for bolting components.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.4. The staff notes that the Bolting Integrity Program is supplemented by other AMPs including but not limited to: the Structures Monitoring, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems, External Surfaces Monitoring, and Buried Piping Inspection programs. These other AMPs supplement the Bolting Integrity Program by implementing the requirements of the Bolting Integrity Program for pressure retaining bolted joints, component support bolting, and structural bolting within the scope of license renewal. The applicant's action accurately adds the related line items to reference the Bolting Integrity Program, however, the technical evaluations documented in the SER do not change since the management of the aging effect will still be implemented by the AMP identified in conjunction with the Bolting Integrity Program.

3.5.2.3.1 Containment, Structures, and Component Supports – Auxiliary Boiler Building – Summary of Aging Management Evaluation – LRA Table 3.5.2-1

The staff reviewed LRA Table 3.5.2-1, which summarizes the results of AMR evaluations for the auxiliary boiler building component groups.

In LRA Table 3.5.2-1, the applicant stated that aluminum bolting exposed to indoor air are being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H for this item, indicating that this aging effect is not in the GALL Report for this component, material, and environment combination.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because aluminum bolting has similar aging effects as other structural bolting materials. The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds that the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because the program conducts visual inspections of exposed bolting surfaces for loss of material due to corrosion, loose nuts, missing bolts, or other indications of loss of preload and relies on plant procedures that are based on the guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide."

For component type "Piles," the applicant stated that concrete encased in steel does not have AERMs and does not require an AMP. This item references Note G and plant-specific Note 4 which states, "Concrete encased in steel is protected from environments that promote age related degradations." The applicant stated that these components have the intended function of structural support. The LRA states that degradation of piles or foundation mats will manifest in settlement distortion or cracking, and accessible concrete examinations will detect cracks and distortion of the structures. The LRA further states that studies have shown that steel piles driven into undisturbed natural soil are not appreciably affected by corrosion due to the oxygen deficiency in soil at a few feet below grade. Piles driven into disturbed soil have been shown to experience only minor to moderate corrosion. In either case, the observed loss of material due to corrosion was not considered significant enough to impact the intended function of the piles, which is consistent with NUREG-1557. The staff reviewed the GALL Report and verified that it includes no AMR item for this component, material, and environment combination. Since the concrete is encased in steel and, therefore, in a protected environment, and auxiliary boiler building concrete foundation structures are monitored under the Structures Monitoring Program for cracks and distortion due to increased stress levels from settlement, the staff finds that a separate AMP for concrete piles encased in steel is not required. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.2 Containment, Structures, and Component Supports – Auxiliary Building Control and Diesel Generator Area – Summary of Aging Management Evaluation – LRA Table 3.5.2-2

The staff reviewed LRA Table 3.5.2-2, which summarizes the results of AMR evaluations for the auxiliary building control and diesel generator area component groups.

In LRA Table 3.5.2-2, the applicant stated that aluminum bolting exposed to indoor air are being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H, indicating that this aging effect is not in the GALL Report for this component, material, and environment combination.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because aluminum bolting has similar aging effects as other structural bolting materials. The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds that the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because the program conducts visual inspections of exposed bolting surfaces for loss of material due to corrosion, loose nuts, missing bolts, or other indications of loss of preload and relies on plant procedures that are based on the guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide."

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-2, the applicant stated that galvanized, carbon, and low alloy steel bolting exposed to outdoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the applicant's Structures Monitoring Program manages loss of preload by conducting visual inspections of exposed bolting surfaces to determine if there is loss of material, loose nuts, missing bolts, or other indications of loss of preload; and that the procedures for installation and selection of materials are based on industry guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide." The staff also noted that GALL AMP XI.M18, "Bolting Integrity," recommends that pressure retaining and structural bolting be managed in accordance with the guidance in EPRI TR-104213. The staff finds the applicant's Structures Monitoring Program acceptable to manage loss of preload for galvanized, carbon, and low alloy steel bolting exposed to indoor air because the applicant plans to monitor these components using visual inspections and plant procedures for bolting installation and selection of materials are based on guidance in EPRI TR-104213, which is consistent with the GALL Report recommendations for management of bolting.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

For one component type, "Penetration Seals," the applicant proposed to assign grout to the Structures Monitoring Program to manage the aging effect of cracking or shrinkage in an air – indoor, air – outdoor, or groundwater or soil environment. This item references Note F and plant-specific Note 3 which states, "Based on industry standards and guidelines, grout is susceptible to cracking due to shrinkage in this environment. However, shrinkage cracking occurs early in plant life and is not expected to be significant for the extended period of operation. Never the less, the aging effect will be monitored through the Structures Monitoring Program." The applicant stated that these components have the intended functions of flood barrier or shelter or protection. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds the applicant's use of the Structures Monitoring Program appropriate because: (1) the program has been enhanced to include building penetrations; (2) the program requires visual inspection of penetration seals for indications of shrinkage and cracking that will lead to loss of sealing; and (3) concrete is inspected for indications of deterioration or distress including evidence of leaching, loss of material, cracking, and loss of bond as defined in ACI 201.1R at a frequency of 5 years. The staff finds that the applicant addressed the AERM adequately.

For one component type, "Penetration Seals," the applicant proposed to assign grout to the Structures Monitoring Program to manage the aging effect of loss of material (spalling, scaling), cracking or freeze-thaw, and increase in porosity and permeability or aggressive chemical attack in an air – outdoor or groundwater or soil environment. This item references Note F and plant-specific Note 4 which states, "The aging effects and Aging Management Program identified for this material and environment combination are consistent with industry guidance." The applicant stated that these components have the intended functions of either flood barrier or shelter or protection. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds the applicant's use of the Structures Monitoring Program appropriate because: (1) the program has been enhanced to include building penetrations; (2) the program requires visual inspection of penetration seals for indications of shrinkage and cracking that will lead to loss of sealing; and (3) concrete is inspected for indications of deterioration or distress including evidence of leaching, loss of material, cracking, and loss of bond as defined in ACI 201.1R at a frequency of 5 years. The staff finds that the applicant addressed the AERM adequately.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.3 Containment, Structures, and Component Supports – Auxiliary Building Service and Radwaste Area – Summary of Aging Management Evaluation – LRA Table 3.5.2-3

The staff reviewed LRA Table 3.5.2-3, which summarizes the results of AMR evaluations for the auxiliary building service and radwaste area component groups.

In LRA Table 3.5.2-3, the applicant stated that aluminum bolting exposed to indoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H for this item, indicating that this aging effect is not in the GALL Report for this component, material, and environment combination.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because aluminum bolting has similar aging effects as other structural bolting materials. The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds that the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because the program conducts visual inspections of exposed bolting surfaces for loss of material due to corrosion, loose nuts, missing bolts, or other indications of loss of preload and relies on plant procedures that are based on the guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide."

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-3, the applicant stated that galvanized, carbon, and low alloy steel bolting exposed to outdoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the applicant's Structures Monitoring Program manages loss of preload by conducting visual inspections of exposed bolting surfaces to determine if there is loss of material, loose nuts, missing bolts, or other indications of loss of preload; and that the procedures for installation and selection of materials are based on industry guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide." The staff also noted that GALL AMP XI.M18, "Bolting Integrity," recommends that pressure retaining and structural bolting be managed in accordance with the guidance in EPRI TR-104213. The staff finds the applicant's Structures Monitoring Program acceptable to manage loss of preload for galvanized, carbon, and low alloy steel bolting exposed to indoor air because the applicant plans to monitor these components using visual inspections and plant procedures for bolting installation and selection of materials are based on guidance in EPRI TR-104213, which is consistent with the GALL Report recommendations for management of bolting.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-3, the applicant stated that lead hatches and plugs exposed to indoor air have no AERM. The AMR item cites generic note F, indicating that the material is not evaluated in the GALL Report for this component, and plant-specific note 3 stating, “Based on plant operating experience, there are no aging effects requiring management for this material and environment combination.”

The staff notes that available technical information revealed no AERMs for lead shielding materials exposed to indoor air environments (e.g., “Corrosion Basics, An Introduction,” NACE Press Book, Second Edition 2006). Therefore, the staff finds the applicant’s determination that there are no AERMs for the lead hatches and plugs exposed to indoor air acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff’s evaluation for grout penetration seals exposed to an air – indoor, air – outdoor, or groundwater or soil environment which are being managed for cracking due to shrinkage by the Structures Monitoring Program with generic note F is documented in SER Section 3.5.2.3.2.

The staff’s evaluation for grout penetration seals exposed to an air – indoor, air – outdoor, or groundwater or soil environment and being managed for loss of material (spalling, scaling), cracking due to freeze-thaw, and increase in porosity and permeability due to aggressive chemical attack by the Structures Monitoring Program with generic note F, is documented in SER Section 3.5.2.3.2.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.4 Containments, Structures, and Component Supports – Summary of Aging Management Evaluation – Component Supports Commodity Group– LRA Table 3.5.2-4

In LRA Table 3.5.2-4, the applicant stated that the nickel-alloy bolting supports for ASME Class 2 and 3 piping and components exposed to flowing water are being managed for loss of material due to galvanic corrosion by the ASME Section XI, Subsection IWF Program. The AMR line item cites generic note J, indicating that neither the component nor the material and environment combination are evaluated in the GALL Report.

The staff reviewed the associated line item in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because loss of material due to localized corrosion like galvanic corrosion may occur for nickel alloys exposed to flowing water such as rainwater.

The staff noted that the nickel-alloy bolting components are made from corrosion resistant base metal and are generally not susceptible to loss of material due to most forms of corrosion, but galvanic corrosion is a special case. The staff noted that galvanic corrosion is also called "two-metal" corrosion because it occurs due to the corrosion potential difference between dissimilar metals that are in contact. The staff noted that the flowing water environment can provide contact between two metals that are not in physical contact. The GALL Report does describe the flowing water environment as "water that is refreshed, and thus having a larger impact on leaching; this can be rainwater, raw water, groundwater, or flowing water under a foundation." Therefore, the staff must consider the possibility of loss of material due to galvanic corrosion because rainwater can provide electrical connection between different metals.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.1.15. The staff noted that the evidence for galvanic corrosion of the nickel-alloy bolting components in flowing water would be surface damage similar to that which could be found in steel components in other environments. The staff noted that periodic visual inspections like those included in the ASME Section XI, Subsection IWF Program are capable of detecting signs of corrosion, corrosion byproducts, discoloration on the surface, scale or deposits, and pits and surface discontinuities that are indicative of loss of material. The staff finds the applicant's proposal to manage aging using the ASME Section XI, Subsection IWF Program acceptable because the program includes periodic visual inspections which are proven capable of detecting loss of material.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-2, the applicant stated that the nickel-alloy bolting supports for ASME Class 2 and 3 piping and components exposed to flowing water are being managed for loss of material due to pitting and crevice corrosion by the ASME Section XI, Subsection IWF Program. The AMR line item cites generic note F, indicating that the material for the AMR line item component is not evaluated in the GALL Report.

The staff reviewed the associated line item in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because loss of material due to localized corrosion like pitting and crevice corrosion may occur for nickel alloys exposed to flowing water.

The staff noted that the nickel-alloy bolting components are made from corrosion resistant base metal and are generally not susceptible to loss of material due to pitting and crevice corrosion in a flowing water environment; however, if the water contains impurities, pitting and/or crevice corrosion can occur. The GALL Report describes the flowing water environment as "water that is refreshed, and thus having a larger impact on leaching; this can be rainwater, raw water, groundwater, or flowing water under a foundation." Therefore, the staff must consider the possibility of loss of material due to pitting and crevice corrosion because rainwater often contains impurities.

The GALL Report does not list nickel-alloy bolting components (supports for ASME Class 2 and 3 piping and components including spring hangers, guides, and stops) exposed to flowing water as susceptible to loss of material due to pitting and crevice corrosion. However, the staff noted that for carbon and low alloy steel bolting components (GALL AMR item III.B1.2-10), the GALL Report recommends managing the loss of material due to general, pitting, and crevice corrosion with the ASME Section XI, Subsection IWF Program. The staff noted that the GALL Report for the loss of material due to general, pitting, and crevice corrosion of the carbon steel components in indoor air would be similar to that which could occur in the nickel-alloy bolting in flowing water.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.1.15. The staff noted that periodic visual inspections like those included in the ASME Section XI, Subsection IWF Program are capable of detecting signs of corrosion, corrosion byproducts, discoloration on the surface, scale or deposits, and pits and surface discontinuities that are indicative of loss of material. The staff finds the applicant's proposal to manage aging using the ASME Section XI, Subsection IWF Program acceptable because the program includes periodic visual inspections which are proven capable of detecting loss of material.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-4, the applicant stated that galvanized, carbon, and low alloy steel bolting exposed to outdoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the applicant's Structures Monitoring Program manages loss of preload by conducting visual inspections of exposed bolting surfaces to determine if there is loss of material, loose nuts, missing bolts, or other indications of loss of preload; and that the procedures for installation and selection of materials are based on industry guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide." The staff also noted that GALL AMP XI.M18, "Bolting Integrity," recommends that pressure retaining and structural bolting be managed in accordance with the guidance in EPRI TR-104213. The staff finds the applicant's Structures Monitoring Program acceptable to manage loss of preload for galvanized, carbon, and low alloy steel bolting exposed to indoor air because the applicant plans to monitor these components using visual inspections and plant procedures for bolting installation and selection of materials are based on guidance in EPRI TR-104213, which is consistent with the GALL Report recommendations for management of bolting.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-4, the applicant stated that carbon steel supports for ASME Class 2 and 3 piping and components exposed to treated water are being managed for loss of mechanical function due to corrosion, distortion, dirt and overload, and fatigue due to vibratory and cyclic thermal loads by both the ASME Section XI Subsection IWF Program and the Water Chemistry Program. The AMR line items cite generic note G, indicating that the environment is not in the GALL Report for this component and material.

The staff's evaluation of the ASME Section XI, Subsection IWF and Water Chemistry programs are documented in SER Sections 3.0.3.1.15 and 3.0.3.2.1, respectively. The staff noted that the applicant's Water Chemistry Program manages loss of mechanical function and fatigue by controlling the concentration of contaminants in the water, and the ASME Section XI, Subsection IWF Program conducts visual inspections to detect degradation before loss of intended functions may occur. The staff finds the applicant's proposed programs acceptable to manage loss of mechanical function and fatigue for ASME Class 2 and 3 piping and component carbon steel supports exposed to treated water because control of water chemistry will mitigate corrosion while visual inspections will be able to detect loss of any mechanical functions or fatigue.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-4, the applicant stated that carbon and low alloy steel supports for ASME Class 2 and 3 piping and components exposed to outdoor air and treated water are being managed for loss of preload due to self-loosening by the ASME Section XI, Subsection IWF Program. The AMR line items for the components exposed to outdoor air cite generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination. The AMR line items for the components exposed to treated water cite generic note G, indicating that the environment is not in the GALL Report for this component and material.

The staff's evaluation of the ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.1.15. The staff noted that the applicant's ASME Section XI, Subsection IWF Program manages loss of preload by conducting visual inspections for missing, detached, or loosened bolts and nuts and its design change procedures are based on the guidance in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide." The staff also noted that GALL AMP XI.M18, "Bolting Integrity," recommends that pressure retaining and structural bolting be managed in accordance with the guidance in EPRI TR-104213. The staff finds the applicant's ASME Section XI, Subsection IWF Program acceptable to manage loss of preload for carbon and low alloy steel supports for ASME Class 2 and 3 piping and components because the applicant plans to monitor these components using visual inspections and plant procedures for bolting installation and selection of materials are based on the guidance in EPRI TR-104213, which is consistent with the GALL Report recommendations for management of bolting.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-4, the applicant stated that carbon steel supports for ASME Class MC components exposed to indoor air are being managed for loss of mechanical function due to corrosion, distortion, dirt and overload, and fatigue due to vibratory and cyclic thermal loads by the ASME Section XI, Subsection IWF Program. The AMR line items cite generic note F, indicating that the material is not in the GALL Report for this component.

The staff's evaluation of the ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.1.15. The staff noted that the applicant's ASME Section XI, Subsection IWF Program manages loss of mechanical function and fatigue by conducting visual inspections for missing, detached, or loosened bolts and nuts; and its design change procedures are based on the guidance in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide." The staff also noted that GALL AMP XI.M18, "Bolting Integrity," recommends that pressure retaining and structural bolting be managed in accordance with the guidance in EPRI TR-104213. The staff finds the applicant's ASME Section XI, Subsection IWF Program acceptable to manage loss of mechanical function due to corrosion, distortion, dirt and overload, and fatigue due to vibratory and cyclic thermal loads because the applicant plans to monitor these components using visual inspections and plant procedures for bolting installation and selection of materials are based on the guidance in EPRI TR-104213, which is consistent with the GALL Report recommendations for management of bolting.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-4, the applicant stated that carbon and low alloy steel bolting supports for ASME Class MC components exposed to treated water are being managed for loss of preload due to self-loosening by the ASME Section XI, Subsection IWF Program. The AMR line items cite generic note G, indicating that the environment is not in the GALL Report for this component and material.

The staff's evaluation of the ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.1.15. The staff noted that the applicant's ASME Section XI, Subsection IWF Program manages loss of preload by conducting visual inspections for missing, detached, or loosened bolts and nuts; and its design change procedures are based on the guidance in the EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide." The staff also noted that GALL AMP XI.M18, "Bolting Integrity," recommends that pressure retaining and structural bolting be managed in accordance with the guidance in EPRI TR-104213. The staff finds the applicant's ASME Section XI, Subsection IWF Program acceptable to manage loss of preload because the applicant plans to monitor these components using visual inspections and plant procedures for bolting installation and selection of materials are based on the guidance in EPRI TR-104213, which is consistent with the GALL Report recommendations for management of bolting.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-4, the applicant stated that stainless steel bolting for supports for ASME Class MC components exposed to treated water are being managed for loss of preload due to self-loosening by the ASME Section XI, Subsection IWF Program. The AMR line items cite generic note G, which indicate that the environment is not addressed in the GALL Report for the component and material.

The staff reviewed the applicant's ASME Section XI, Subsection IWF Program and its evaluation is documented in SER Section 3.0.3.1.15. The staff finds the applicant's program acceptable to manage aging for these components because it performs visual inspections for missing, detached, or loosened bolts to detect loss of preload, and it has incorporated industry guidance on good bolting practices into its installation procedures.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-4, the applicant stated that stainless steel bolting for supports for ASME Class 1, 2 and 3 piping are being managed for loss of preload due to self-loosening by the ASME Section XI, Subsection IWF Program. The applicant also stated that stainless steel bolting for supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, and non-ASME piping and components exposed to indoor air are being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H, which indicates that the aging effect is not addressed in the GALL Report for the component, material, and environment combination.

The staff reviewed the applicant's ASME Section XI, Subsection IWF and Structures Monitoring programs and its evaluations are documented in SER Sections 3.0.3.1.15 and 3.0.3.2.16, respectively. The staff finds the applicant's proposed programs acceptable to manage loss of preload for these components because both programs include visual inspections for missing or loosened bolts to detect loss of preload, and they have incorporated industry guidance on good bolting practices into the installation procedures.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.5 Containment, Structures, and Component Supports – Fire Water Pump House – Summary of Aging Management Evaluation – LRA Table 3.5.2-5

The staff reviewed LRA Table 3.5.2-5, which summarizes the results of AMR evaluations for the fire water pump house component groups.

In LRA Table 3.5.2-5, the applicant stated that galvanized, carbon, and low alloy steel bolting exposed to outdoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the applicant's Structures Monitoring Program manages loss of preload by conducting visual inspections of exposed bolting surfaces to determine if there is loss of material, loose nuts, missing bolts, or other indications of loss of preload; and that the procedures for installation and selection of materials are based on industry guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide." The staff also noted that GALL AMP XI.M18, "Bolting Integrity," recommends that pressure retaining and structural bolting be managed in accordance with the guidance in EPRI TR-104213. The staff finds the applicant's Structures Monitoring Program acceptable to manage loss of preload for galvanized, carbon, and low alloy steel bolting exposed to indoor air because the applicant plans to monitor these components using visual inspections and plant procedures for bolting installation and selection of materials are based on guidance in EPRI TR-104213, which is consistent with the GALL Report recommendations for management of bolting.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Tables 3.5.2-5 and 3.5.2-6, the applicant stated that fiberglass doors and insulation exposed to indoor or outdoor air and fiberglass insulation jacketing (includes wire mesh, tie wires, straps and clips) exposed to indoor air have no AERM. For the AMR items in Table 3.5.2-5, the applicant cited generic note F, indicating that the material is not addressed in the GALL Report for the component and for the AMR items in Table 3.5.2-6 the applicant cited generic note J, indicating that neither the component nor the material and environment combination is evaluated in the GALL Report. The applicant further cited a plant-specific note for these items stating, "Based on plant operating experience, there are no aging effects requiring management for this material and environment combination."

The staff finds the applicant's proposal acceptable for the fiber glass insulation and fiberglass insulation jacketing (includes wire mesh, tie wires, straps and clips) components exposed to indoor or outdoor air because, based on a review of industry operating experience, these components in these environments have exhibited no age-related degradation when covered by aluminum insulation jacketing (see aluminum insulation jacketing line items in Table 3.5.2-6).

The staff did not have sufficient information to evaluate the aging effects for the fiberglass doors exposed to indoor or outdoor air. By letter dated June 29, 2010, the staff issued RAI 3.5.2.3.5-01 requesting that the applicant state whether or not the fiberglass doors are exposed to direct ultraviolet (UV) lighting or ozone for the indoor application and for the outdoor air application, state how the doors are protected from environmental effects such as rain and sunlight, or propose how the aging effects of loss of material and change in material properties will be managed.

In its response dated July 16, 2010, the applicant stated that it had inadvertently omitted the aging effects of loss of material and change in material properties due to exposure to UV or ozone. The applicant also stated that it revised Table 3.5.2-5 to include this aging effect for these doors and indicate that the Structures Monitoring Program would be used to manage the aging effect. The applicant further stated that its Structures Monitoring Program would be revised to require a 5-year inspection of the doors.

The staff finds the applicant’s response acceptable because the LRA has been corrected to reflect that an aging effect would occur due to exposure to UV and ozone and a 5-year visual inspection conducted as part of the Structures Monitoring Program would reveal degradation of the doors prior to their CLB basis function being affected because the environmental effects would not progress at a rapid rate given the relatively low levels of UV and ozone exposure at the door locations. The staff’s concern described in RAI 3.5.2.3.5-01 is resolved.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff’s evaluation for grout penetration seals exposed to an air – indoor or air – outdoor environment which are being managed for cracking due to shrinkage by the Structures Monitoring Program with generic note F is documented in SER Section 3.5.2.3.2.

The staff’s evaluation for concrete filled steel piles, with no aging effect and no credited AMP and referencing generic note F, is documented in SER Section 3.5.2.3.1.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.6 Containment, Structures, and Component Supports – Piping and Component Insulation Commodity Group – Summary of Aging Management Evaluation – LRA Table 3.5.2-6

The staff reviewed LRA Table 3.5.2-6, which summarizes the results of AMR evaluations for the piping and component insulation commodity group component groups.

In LRA Table 3.5.2-6, the staff’s evaluation for fiberglass insulation exposed to outdoor or indoor air having no aging effect and no AMP with generic note J, indicating that neither the component nor the material and environment combination is evaluated in the GALL Report, is documented in SER Section 3.5.2.3.5

For component type “Insulation,” the applicant stated that “Min-K,” calcium silicate, cellular glass, ceramic fiber, fiberglass (molded), and NUKON in an air – indoor or air – outdoor environment having an intended function of insulation does not have AERMs and does not require an AMP. The applicant also stated for component type, insulation jacketing (includes wire mesh, tie wires, straps, clips), the fiberglass cloth in an air – indoor environment having an intended function of either shelter or protection or structural support also does not have AERMs. Both of these items reference Note J and plant-specific Note 1 which states, “Based on plant operating experience, there are no aging effects requiring management for this material and environment combination.” The LRA also states that the purpose of piping and component insulation is to improve thermal efficiency, minimize heat loads on the HVAC systems, provide for personnel protection, prevent freezing of heat traced piping, or protect against sweating of cold piping and components. Insulation located in areas with safety-related equipment is designed to protect nearby safety-related SSC equipment from overheating and maintain its structural integrity during postulated design-basis seismic events. Insulation within primary containment has been evaluated to ensure that it will not affect the ECCS suction strainers. The insulation and insulation jacketing (includes wire mesh, straps, clips) perform an intended function and are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff reviewed the GALL Report and verified that it includes no AMR item for this component, material, and environment combination. Since the piping and component insulation commodity group is not classified as a safety-related commodity and the thermal insulation is typically passive and long-lived, the staff concludes there are no applicable AERMs for the materials or environments identified in the table and that the applicant need not credit an AMP.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.7 Containment, Structures, and Component Supports – Primary Containment – Summary of Aging Management Evaluation – LRA Table 3.5.2-7

The staff reviewed LRA Table 3.5.2-7, which summarizes the results of AMR evaluations for the primary containment component groups.

For one component type “Coating,” in either an air – indoor or air with treated water environment, the applicant stated that the paint material is managed for cracking, blistering, flaking, peeling, and delamination. This item references Note J. The applicant stated that this component has an intended function to maintain adhesion and is examined using the Protective Coating Monitoring and Maintenance Program as the primary AMP. The staff’s review of the applicant’s Protective Coating Monitoring and Maintenance Program is documented in SER Section 3.0.3.1.17. The Protective Coating Monitoring and Maintenance Program manages cracking, blistering, flaking, peeling, and delamination of Service Level I coatings in accessible areas of the containment structure subjected to an indoor air environment during refueling outages through visual inspections performed by qualified individuals knowledgeable in nuclear coatings. The applicant also stated that more thorough inspections of suspect areas are conducted and, when appropriate, additional testing may be done to characterize the severity of observed deficiencies. The Protective Coating Monitoring and Maintenance Program is consistent with coating monitoring requirements in RG 1.54 (Revision 1) and GL 98-04 and follows guidelines in ASTM D 5163-05(a). Since the Protective Coating Monitoring and Maintenance Program is used to verify coating adhesion and thus prevent blockage of the suction strainers, the staff finds that the applicant has committed to an appropriate AMP for the period of extended operation. The staff finds that the applicant addressed the AERM adequately.

For one component type, concrete (interior biological shield), having either a shielding or a structural support function, the applicant stated that concrete, concrete (high density), and grout (high density) encased in steel has no AERMs and does not require an AMP. The applicant also stated for component type “Doors,” the boron concrete in an encased in steel environment having an intended function of shielding also does not have AERMs and an AMP is not required. These items references either Note F or Note G and plant-specific Note 4 which states, “Concrete or Concrete (High Density) or Grout (High Density) or Boron Concrete encased in steel is protected from environments that promote age related degradation.” The staff reviewed the GALL Report and verified that it includes no AMR item for this component, material, and environment combination. Since the concrete is encased in steel and, therefore, in a protected environment and the LRA states that concrete structural components are not subject to general area temperatures greater than 150 °F or local area temperatures greater than 200 °F, the staff finds that the concrete is not subjected to AERMs that would diminish its capacity to meet its intended function of shielding or structural support and that the applicant need not credit an AMP.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.8 Containment, Structures, and Component Supports – Reactor Building – Summary of Aging Management Evaluation – LRA Table 3.5.2-8

The staff reviewed LRA Table 3.5.2-8, which summarizes the results of AMR evaluations for the intake screen and pump house component groups.

In LRA Table 3.5.2-8, the applicant stated that aluminum bolting exposed to indoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H for this item, indicating that this aging effect is not in the GALL Report for this component, material, and environment combination.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because, aluminum bolting has similar aging effects as other structural bolting materials. The staff’s evaluation of the applicant’s Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds that the applicant’s proposal to manage aging using the Structures Monitoring Program acceptable because the program conducts visual inspections of exposed bolting surfaces for loss of material due to corrosion, loose nuts, missing bolts, or other indications of loss of preload and relies on plant procedures that are based on the guidance contained in EPRI TR-104213, “Bolted Joint Maintenance and Applications Guide.”

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-8, the applicant stated that galvanized, carbon, and low alloy steel bolting exposed to outdoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the applicant's Structures Monitoring Program manages loss of preload by conducting visual inspections of exposed bolting surfaces to determine if there is loss of material, loose nuts, missing bolts, or other indications of loss of preload; and that the procedures for installation and selection of materials are based on industry guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide." The staff also noted that GALL AMP XI.M18, "Bolting Integrity," recommends that pressure retaining and structural bolting be managed in accordance with the guidance in EPRI TR-104213. The staff finds the applicant's Structures Monitoring Program acceptable to manage loss of preload for galvanized, carbon, and low alloy steel bolting exposed to indoor air because the applicant plans to monitor these components using visual inspections and plant procedures for bolting installation and selection of materials are based on guidance in EPRI TR-104213, which is consistent with the GALL Report recommendations for management of bolting.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

For component types "Concrete (interior) and Hatches or Plugs," the applicant stated that reinforced concrete encased in steel having a shielding or structural support function has no AERMs and does not require an AMP. This item references Note G and plant-specific Note 3 which states, "Concrete encased in steel is protected from environments that promote age related degradations." The staff reviewed the GALL Report and verified that it includes no AMR item for this component, material, and environment combination. Since the concrete is encased in steel and, therefore, in a protected environment in the reactor building and the LRA states that concrete structural components are not subject to general area temperatures greater than 150 °F or local area temperatures greater than 200 °F, the staff finds that the concrete is not subjected to AERMs that would diminish its capacity to meet its intended function of structural support and that the applicant need not credit an AMP.

The staff's evaluation for grout penetration seals exposed to an air – indoor, air – outdoor, or groundwater or soil environment which are being managed for loss of material (spalling, scaling), cracking due to freeze-thaw, and increase in porosity and permeability due to aggressive chemical attack by the Structures Monitoring Program with generic note F is documented in SER Section 3.5.2.3.2.

The staff's evaluation for grout penetration seals exposed to an air – indoor, air – outdoor, or groundwater or soil environment which are being managed for cracking due to shrinkage by the Structures Monitoring Program with generic note F is documented in SER Section 3.5.2.3.2.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.9 Containment, Structures, and Component Supports – Service Water Intake Structure – Summary of Aging Management Evaluation – LRA Table 3.5.2-9

The staff reviewed LRA Table 3.5.2-9, which summarizes the results of AMR evaluations for the service water intake structure component groups.

For component type "Bolting (Structural)" in an air – indoor, air – outdoor, or water flowing environment, the applicant stated that aluminum bolting, carbon and low alloy steel bolting, and galvanized steel bolting having an intended function of structural support is being managed for loss of preload due to self-loosening by the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program. This item references Note H and plant-specific Note 1 which states:

> Based on industry standards and operating experience age related loss of preload due to self-loosening of structural bolting could be caused by vibration, flexing of the joint or cyclic shear loads that could occur in any environment. However, these causes are considered in the design of structural connections and eliminated by the initial preload bolt torquing. Thus, loss of preload due to self-loosening of structural bolting is not significant and will not impact structural intended functions. Never the less, loss of preload due to self-loosening will be monitored through the Structures Monitoring Program.

The staff's review of the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program is documented in SER Section 3.0.3.2.17. The staff finds the applicant's use of the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program appropriate because the program: (1) manages loss of material and loss of preload for steel and metal components; (2) monitors accessible surfaces on a frequency of 5 years; (3) has been enhanced to include inspection of SCs submerged in water at a frequency of 5 years; (4) is implemented through the Structures Monitoring Program which monitors exposed surfaces of bolting for loss of material due to corrosion, loose nuts, missing bolts, or other indications of loss of preload; and (5) the program incorporates procedures based on EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide," to ensure proper specification of bolting material, lubricant, and installation torque. The staff finds that the applicant addressed the AERM adequately.

For component types "Concrete (above- and below-grade exterior), Concrete Foundation, and Concrete (interior)" in a water-flowing or groundwater or soil environment the applicant stated that the reinforced concrete having an intended function of either flood barrier, missile barrier, shelter or protection, structural support, or direct flow is managed for: (1) cracking, loss of bond, and loss of material (spalling and scaling) due to corrosion of embedded steel; and (2) increase in porosity and permeability, cracking, loss of material (spalling or scaling) due to aggressive chemical attack, by the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program. This item references Note H and plant-specific Note 2 which states, "The aging effects and Aging Management Program identified for this material and environments combination are consistent with industry guidance." The LRA states that the Structures Monitoring Program is used to implement the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program. The staff's review of the applicant's RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program is documented in SER Section 3.0.3.2.17. The staff finds the applicant's use of the

RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" Program appropriate because the program: (1) manages reinforced concrete members for loss of material, cracking, and change in material properties; (2) has been enhanced to visually inspect water-control structures, including SCs submerged in water, on a frequency of 5 years; and (3) is based on guidance provided in RG 1.127 and ACI 349.3R. The staff finds that the applicant addressed the AERM adequately.

For component type "Ice Barrier," in either an air – outdoor or water flowing environment the applicant stated that the treated wood is managed for change in material properties, loss of material due to moisture damage, and insect damage by the Structures Monitoring. This item references Note J. The LRA states that these components have the intended function of shelter or protection and are in the form of treated wood that is designed to prevent ice blockage of the service water intake structure. The design of the ice barriers incorporates marine dock bumpers to reduce impact load on the structure in the event barges or ships drift into the vicinity of the intake structure. The staff's review of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.16. Since the Structures Monitoring Program has been enhanced to monitor wooden components for change in material properties and loss of material due to insect damage and moisture damage, and visual inspections are conducted on a frequency not to exceed 5 years, the staff finds that the applicant has committed to an appropriate AMP for the period of extended operation. The staff finds that the applicant addressed the AERM adequately.

The staff's evaluation for grout penetration seals exposed to an air – indoor, air – outdoor, or groundwater or soil environment which are being managed for loss of material (spalling, scaling), cracking due to freeze-thaw, and increase in porosity and permeability due to aggressive chemical attack by the Structures Monitoring Program with generic note F is documented in SER Section 3.5.2.3.2.

The staff's evaluation for grout penetration seals exposed to an air – indoor, air – outdoor, or groundwater or soil environment which are being managed for cracking due to shrinkage by the Structures Monitoring Program with generic note F is documented in SER Section 3.5.2.3.2.

The staff's evaluation for concrete filled steel piles, with no aging effect and no credited AMP and referencing generic note G, is documented in SER Section 3.5.2.3.1.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.10 Containment, Structures, and Component Supports –Shoreline Protection and Dike– Summary of Aging Management Evaluation – LRA Table 3.5.2-10

The staff reviewed LRA Table 3.5.2-10, which summarizes the results of AMR evaluations for the shoreline protection and dike component groups.

For component type "Earthen Water-Control Structures or Embankments (dikes)" in an air – outdoor environment, the applicant stated that soil, rip-rap, sand, and gravel having an intended function of shelter or protection are managed for loss of material, loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage by the RG

1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program. This item references Note G and plant-specific Notes 1 and 2. Plant-specific Note 1 states, “Based on industry standards and guidelines, earthen water-control structures are susceptible to loss of material and loss of form in Air-Outdoor environment.” Plant-specific Note 2 states, RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” is the applicable aging management program for this component.” The LRA states that the RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program is implemented through the Structures Monitoring Program. The staff’s review of the applicant’s RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” and the Structures Monitoring programs and is documented in SER Section 3.0.3.2.17 and 3.0.3.2.16, respectively. Since the RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” Program is based on guidance provided in RG 1.127 that addresses aging effects noted above, and is implemented through the Structures Monitoring Program that conducts visual inspections on a frequency not to exceed 5 years of the earthen structures associated with water-control structures for loss of material and loss of form, the staff agrees that the applicant has committed to an appropriate AMP for the period of extended operation. The staff finds that the applicant addressed the AERM adequately.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.11 Containment, Structures, and Component Supports – Switchyard – Summary of Aging Management Evaluation – LRA Table 3.5.2-11

The staff reviewed LRA Table 3.5.2-11, which summarizes the results of AMR evaluations for the switchyard component groups.

In LRA 3.5.2-11 the applicant stated that galvanized, carbon, and low alloy steel bolting exposed to outdoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination.

The staff’s evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the applicant’s Structures Monitoring Program manages loss of preload by conducting visual inspections of exposed bolting surfaces to determine if there is loss of material, loose nuts, missing bolts, or other indications of loss of preload; and that the procedures for installation and selection of materials are based on industry guidance contained in EPRI TR-104213, “Bolted Joint Maintenance and Applications Guide.” The staff also noted that GALL AMP XI.M18, “Bolting Integrity,” recommends that pressure retaining and structural bolting be managed in accordance with the guidance in EPRI TR-104213. The staff finds the applicant’s Structures Monitoring Program acceptable to manage loss of preload for galvanized, carbon, and low alloy steel bolting exposed to indoor air because the applicant plans to monitor these components using visual inspections and plant procedures for bolting installation and selection of materials are based on guidance in EPRI TR-104213, which is consistent with the GALL Report recommendations for management of bolting.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff's evaluation for concrete filled steel piles, with no aging effect and no credited AMP and referencing generic note G, is documented in SER Section 3.5.2.3.1.

In LRA Table 3.5.2-11, the applicant stated that polyvinyl chloride (PVC) conduit exposed to concrete has no AERM and that for this component, material, environment combination, no AMP is needed. The AMR line items cite generic note J, indicating that neither the component nor the material and environment combination is evaluated in the GALL Report. The staff reviewed the GALL Report and confirmed that neither the conduit nor PVC is included therein.

For these AMR results, the applicant also cited plant-specific note 2 stating that the PVC is encased in concrete and has no aging effects for the identified environment. The staff notes that given the component's switchyard location with potential proximity to high-voltage equipment or exposure to sunlight, PVC components could be susceptible to known stressors such as UV light or ozone. The staff finds the applicant's determination that no AMP is needed acceptable because given that the PVC pipe is encased in concrete and the material will not be exposed to significant UV light or ozone.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment AERM and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.12 Containment, Structures, and Component Supports – Turbine Building – Summary of Aging Management Evaluation – LRA Table 3.5.2-12

The staff reviewed LRA Table 3.5.2-12, which summarizes the results of AMR evaluations for the turbine building component groups.

In LRA Table 3.5.2-12, the applicant stated that aluminum bolting exposed to indoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H for this item, indicating that this aging effect is not in the GALL Report for this component, material, and environment combination.

The staff reviewed the associated line items in the LRA and confirmed that the applicant has identified the correct aging effects for this component, material, and environment combination because, aluminum bolting has similar aging effects as other structural bolting materials. The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds that the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because the program conducts visual inspections of exposed bolting surfaces for loss of material due to corrosion, loose nuts, missing bolts, or other indications of loss of preload and relies on plant procedures that are based on the guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide."

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.5.2-12, the applicant stated that galvanized, carbon, and low alloy steel bolting exposed to outdoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the applicant's Structures Monitoring Program manages loss of preload by conducting visual inspections of exposed bolting surfaces to determine if there is loss of material, loose nuts, missing bolts, or other indications of loss of preload; and that the procedures for installation and selection of materials are based on industry guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide." The staff also noted that GALL AMP XI.M18, "Bolting Integrity," recommends that pressure retaining and structural bolting be managed in accordance with the guidance in EPRI TR-104213. The staff finds the applicant's Structures Monitoring Program acceptable to manage loss of preload for galvanized, carbon, and low alloy steel bolting exposed to indoor air because the applicant plans to monitor these components using visual inspections and plant procedures for bolting installation and selection of materials are based on guidance in EPRI TR-104213, which is consistent with the GALL Report recommendations for management of bolting.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff's evaluation for grout penetration seals exposed to an air – indoor, air – outdoor, or groundwater or soil environment which are being managed for loss of material (spalling, scaling), cracking due to freeze-thaw, and increase in porosity and permeability due to aggressive chemical attack by the Structures Monitoring Program with generic note F is documented in SER Section 3.5.2.3.2.

The staff's evaluation for grout penetration seals exposed to an air – indoor, air – outdoor, or groundwater or soil environment which are being managed for cracking due to shrinkage by the Structures Monitoring Program with generic note F is documented in SER Section 3.5.2.3.2.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.13 Containment, Structures, and Component Supports – Yard Structures – Summary of Aging Management Evaluation – LRA Table 3.5.2-13

The staff reviewed LRA Table 3.5.2-13, which summarizes the results of AMR evaluations for the yard structures component groups.

In LRA Table 3.5.2-13, the applicant stated that galvanized, carbon, and low alloy steel bolting exposed to outdoor air is being managed for loss of preload due to self-loosening by the Structures Monitoring Program. The AMR line items cite generic note H, indicating that the aging effect is not in the GALL Report for this component, material, and environment combination.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the applicant's Structures Monitoring Program manages loss of preload by conducting visual inspections of exposed bolting surfaces to determine if there is loss of material, loose nuts, missing bolts, or other indications of loss of preload; and that the procedures for installation and selection of materials are based on industry guidance contained in EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide." The staff also noted that GALL AMP XI.M18, "Bolting Integrity," recommends that pressure retaining and structural bolting be managed in accordance with the guidance in EPRI TR-104213. The staff finds the applicant's Structures Monitoring Program acceptable to manage loss of preload for galvanized, carbon, and low alloy steel bolting exposed to indoor air because the applicant plans to monitor these components using visual inspections and plant procedures for bolting installation and selection of materials are based on guidance in EPRI TR-104213, which is consistent with the GALL Report recommendations for management of bolting.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff's evaluation for polyvinyl chloride conduit embedded in concrete with no aging effect and no credited AMP and referencing generic note J, is documented in SER Section 3.5.2.3.11.

The staff's evaluation for concrete filled steel piles, with no aging effect and no credited AMP and referencing generic note G, is documented in SER Section 3.5.2.3.1.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that, the effects of aging for the structures and component supports within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6 <u>Aging Management of Electrical and Instrumentation and Control</u>

The following information documents the staff's review of the applicant's AMR results for the electrical and instrumentation and control (I&C) components and component groups of:

- cable connections (metallic parts)
- fuse holders – metallic clamp
- high-voltage insulators
- insulated cables and connections
- metal enclosed bus
- switchyard bus and connections, transmission conductors and connections

3.6.1 Summary of Technical Information in the Application

LRA Section 3.6 provides a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the electrical components, I&C components and component groups. The applicant stated that electrical penetrations are not subject to their own AMR in this section in that they are addressed: (1) as a TLAA in the EQ program, (2) as part of the insulated cables and connections commodity group, and (3) in the primary containment AMR (Table 3.5.2-7).

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussion with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues since the issuance of the GALL Report.

3.6.2 Staff Evaluation

The staff reviewed LRA Section 3.6 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the electrical and I&C components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff reviewed AMRs to ensure the applicant's claim that certain AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant has identified the appropriate GALL Report AMPs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's evaluation are documented in SER Section 3.6.2.1.

The staff also reviewed AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.6.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 3.6.2.2.

Table 3.6-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.6 and addressed in the GALL Report.

Table 3.6-1 Staff Evaluation for Electrical and Instrumentation and Controls in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 environmental qualification (EQ) requirements (3.6.1-1)	Degradation due to various aging mechanisms	Environmental Qualification of Electric Components	Yes	TLAA	Environmental Qualification is a TLAA (See SER Section 3.6.2.2.1)
Electrical cables, connections and fuse holders (insulation) not subject to 10 CFR 50.49 EQ requirements (3.6.1-2)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	No	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	Consistent with GALL Report
Conductor insulation for electrical cables and connections used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation resistance (3.6.1-3)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables And Connections Used In Instrumentation Circuits Not Subject to 10 CFR 50.49 EQ Requirements	No	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used In Instrumentation Circuits	Consistent with GALL Report
Conductor insulation for inaccessible medium voltage (2-kV to 35-kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements (3.6.1-4)	Localized damage and breakdown of insulation leading to electrical failure due to moisture intrusion, water trees	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements	No	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Connector contacts for electrical connectors exposed to borated water leakage (3.6.1-5)	Corrosion of connector contact surfaces due to intrusion of borated water	Boric Acid Corrosion	No	Not applicable	Not applicable to BWRs
Fuse Holders (Not Part of a Larger Assembly): Fuse holders - metallic clamp (3.6.1-6)	Fatigue due to ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, and oxidation	Fuse Holders	No	Not applicable	Not applicable to HCGS
Metal enclosed bus - bus, connections (3.6.1-7)	Loosening of bolted connections due to thermal cycling and ohmic heating	Metal Enclosed Bus	No	Metal Enclosed Bus	Consistent with GALL Report
Metal enclosed bus - insulation, insulators (3.6.1-8)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Metal Enclosed Bus	No	Metal Enclosed Bus	Consistent with GALL Report
Metal enclosed bus - enclosure assemblies (3.6.1-9)	Loss of Material/ General Corrosion	Structures Monitoring Program	No	Not applicable	Not applicable to HCGS (See SER Section 3.6.2.1.1)
Metal enclosed bus - enclosure assemblies (3.6.1-10)	Hardening and loss of strength due to elastomers degradation	Structures Monitoring Program	No	Structures Monitoring Program	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High-voltage insulators (3.6.1-11)	Degradation of insulation quality due to presence of any salt deposits and surface contamination; loss of material caused by mechanical wear due to wind blowing on transmission conductors	A plant-specific AMP is to be evaluated.	Yes	High Voltage Insulators	Consistent with GALL Report (See SER Section 3.6.2.2)
Transmission conductors and connections; switchyard bus and connections (3.6.1-12)	Loss of material due to wind induced abrasion and fatigue; loss of conductor strength due to corrosion; increased resistance of connection due to oxidation or loss of preload	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to HCGS (See SER Section 3.6.2.2.3)
Cable Connections - metallic parts (3.6.1-13)	Loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	No	Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements	Consistent with GALL Report
Fuse Holders (Not Part of a Larger Assembly) - insulation material (3.6.1-14)	None	None	No	None	Consistent with GALL Report

The staff's review of the electrical and I&C component groups followed any one of several approaches. One approach, documented in SER Section 3.6.2.1, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.6.2.2, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.6.2.3, reviewed AMR results for components that the applicant indicated are not consistent with or not addressed in the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the electrical and I&C components is documented in SER Section 3.0.3.

3.6.2.1 AMR Results That Are Consistent with the GALL Report

LRA Section 3.6.2.1 identifies the materials, environments, and aging effects requiring management, and the following programs that manage aging effects for the electrical and I&C components:

- Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits
- Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements
- Metal Enclosed Bus
- Structures Monitoring Program

In LRA Table 3.6.1, the applicant summarizes AMRs for the electrical and instrumentation and controls components and claimed that these AMRs are consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the report and for which the GALL Report does not recommend further evaluation, the staff's review determined whether the plant-specific components of these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant noted for each AMR line item how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with notes A through E indicating how the AMR is consistent with the GALL Report.

The staff reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

The staff reviewed the LRA to confirm that the applicant: (a) provided a brief description of the system, components, materials, and environments; (b) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (c) identified those aging effects for the electrical and I&C components that are subject to an AMR. On the basis of its review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.6.1, the applicant's references to the GALL Report are acceptable, and no further staff review is required.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with its AMRs. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.6-1, item 3.6.1-9 addresses aging effect of loss of material caused by the mechanisms of pitting and crevice corrosion for aluminum metal enclosed bus enclosure assemblies exposed to indoor air and stated that there is no AERM and no AMP is recommended. In LRA Table 3.5-1, item 3.5.1-58, the applicant stated that the galvanized steel and aluminum support members, welds, bolted connections, and support anchorages to building structure exposed to indoor air for the material and environment combination do not have AERMs. The applicant also stated that no AMPs are applicable to the aluminum items exposed to indoor air for the electrical commodities system associated with this item number. The GALL Report item III.B5-2, which corresponding to Table 3.5.1, item 3.5.1-58, recommends no AMP for this component group and, therefore, the staff finds the applicant's determination acceptable.

3.6.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

In LRA Section 3.6.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the electrical and I&C components and provides information concerning how it will manage the following aging effects:

- electrical equipment subject to EQ
- degradation of insulator quality due to salt deposits or surface contamination, loss of material due to mechanical wear
- loss of material due to wind induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the GALL Report recommends further evaluation, the staff reviewed the corresponding AMR items 3.6.1-11 and 3.6.1-12 in LRA Table 3.6.1. The staff also reviewed applicant's evaluation to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.6.2.2. The staff's review of the applicant's further evaluation follows.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

LRA Section 3.6.2.2.1 refers to Table 3.6.1, item 3.6.1-1 and the applicant provides an evaluation of EQ TLAAs. SER Section 4.4 documents the staff's review of the applicant's evaluation of this TLAA.

3.6.2.2.2 Degradation of Insulator Quality Due to Presence of Any Salt Deposits and Surface Contamination, and Loss of Material Due to Mechanical Wear

LRA Section 3.6.2.2.2 refers to Table 3.6.1, item 3.6.1-11. LRA Section 3.6.2.2.2 addresses degradation of insulator quality due to salt deposits or surface contamination and loss of material due to mechanical wear. The applicant stated that the high-voltage insulators evaluated for HCGS are those used to support in-scope, uninsulated, high-voltage electrical commodities such as transmission conductors and switchyard bus. The supported commodities are those credited for supplying power to in-scope components for recovery of offsite power following an SBO. The majority of insulators within the scope of license renewal at HCGS is configured vertically and is designed with an increased creepage distance that is able to withstand “heavy to very heavy” pollution severity levels. Vertical insulators with increased creepage distance are less susceptible to flashover due to surface contamination. Horizontal overhead transmission line insulators are angled to form various “string” configurations, making them susceptible to surface contamination.

The applicant also stated that HCGS is located in a rural area, not near heavy industry that would provide a source for contaminants, and is not in close proximity to the Atlantic Ocean. The station is located at the end of the Delaware River (at the head of Delaware Bay), 50 miles from the Atlantic Ocean. Therefore, HCGS is not considered to be a seacoast plant, where salt spray is prevalent. The applicant stated that site-specific operating experience has shown that flashover of insulators due to contamination from salt spray is an applicable aging mechanism that requires management. One plant-specific event occurred at HCGS in September 2003, when Hurricane Isabel passed a considerable distance to the south and west of the site. Strong winds with gusts in excess of 60 mph caused switchyard insulators to become coated with salt. The applicant stated that it will implement a plant-specific High Voltage Insulators Program to detect the buildup of surface contamination on high-voltage insulators in the HCGS Switchyard and the Salem-HCGS 500-kV cross-connection (the 5037 line).

The applicant stated that mechanical wear is an aging effect for strain and suspension insulators in that they are subject to movement. Movement of the insulator can be caused by wind blowing the supported transmission conductor, causing it to swing from side to side. The applicant also stated that if this swing is frequent enough, it could cause wear in the metal contact points of the insulator string and between an insulator and the supporting hardware. Although this mechanism is possible, the applicant stated that experience has shown that the transmission conductors do not normally swing and that when they do, due to substantial wind, they do not continue to swing for very long once the wind has subsided. Wind loading that can cause a transmission line and insulators to sway is considered in the design and installation. The applicant further stated that, although rare, surface rust of the metallic cap may form where the galvanized coating is burned off due to flashover from lightning strikes. Surface rust is not a significant concern and would not cause a loss of intended function if left unmanaged for the period of extended operation. The applicant also stated that wear and surface rust has not been identified during routine switchyard inspections.

The staff reviewed LRA Section 3.6.2.2.2 against SRP-LR Section 3.6.2.2.2, which states that degradation of insulator quality due to salt deposits or surface contamination may occur in high-voltage insulators. The GALL Report recommends further evaluation of plant-specific AMPs for plants at locations of potential salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution). Loss of material due to mechanical wear caused by wind on transmission conductors may occur in high-voltage insulators. The GALL

Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

The staff noted various airborne materials such as dust, salt and industrial effluents can contaminate insulator surfaces. However, the buildup of surface contamination is gradual and in most areas such contamination is washed away by rain; the glazed insulator surface aids this contamination removal. Surface contamination can be a problem in areas where the greatest concentration of airborne particles such as near facilities that discharge soot or near the sea coast where salt spray is prevalent. Plant-specific operating experience at HCGS has shown that flashover of high-voltage insulator due to salt spray is an applicable aging mechanism that requires management. As described above, one plant-specific event occurred at HCGS in September 2003, when Hurricane Isabel passed a considerable distance to the south and west of the site. Strong winds with gusts in excess of 60 mph caused switchyard insulators to become coated with salt. The applicant proposed a plant-specific High Voltage Insulator Program to manage the buildup of salt deposits on high-voltage insulators. The staff evaluated this program in Section 3.0.3 of the SER. The staff determined that this AMP is acceptable because visual inspection is appropriate to inspect surface contamination for salt deposit.

The staff determined that although loss of material of insulators due to mechanical wear is possible, wind loading that can cause a transmission line and insulators to vibrate or sway is considered in HCGS's design and installation. Surface rust is not a significant aging effect because it would not cause a loss of intended function for insulation if left unmanaged for the period of extended operation. In addition, the applicant has not identified any wear or surface rust of insulators during routine inspections. Based on its review, the staff finds that mechanical wear or surface rust aging effect of high-voltage insulators is not an AERM.

Based on the programs identified above, the staff concludes that the applicant has met the SRP-LR Section 3.6.2.2.2 criteria. For those line items that apply to LRA Section 3.6.2.2.2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.3 Loss of Material Due to Wind–Induced Abrasion and Fatigue, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload

In LRA Section 3.6.2.2.3, the applicant stated that the transmission conductors and connections evaluated for HCGS are those credited for supplying power to in-scope components for recovery of offsite power following an SBO. The applicant also stated that aging management activities regarding loss of conductor strength due to corrosion for HCGS transmission conductors are not required for the period of extended operation because the HCGS transmission conductors are not susceptible to corrosion. This aging effect refers to Table 3.6.1, item 3.6.1-13. The in-scope transmission conductors at HCGS are 2493 MCM 54/37 aluminum conductor, aluminum-alloyed reinforced (ACAR) overhead electrical conductors. Each phase has two conductors. These transmission conductors are approximately 1.8 inches in diameter and are configured with 37 aluminum-alloyed conductor wire strands wrapped by 54 aluminum conductor wire strands. The applicant further stated that PSE&G Transmission & Distribution design practices follows the National Electrical Safety Code (NESC) methodologies. NESC Section 250.B sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind and temperature. NESC Section 260.H.1.a requires that heavy load tension on installed conductors be less than 60 percent of the ultimate conductor strength. ACAR conductors are similar in construction to steel-reinforced design except that the core is an aluminum alloy that gives the conductor higher mechanical strength than that of all-aluminum conductor, while maintaining corrosion resistant properties in the core. In addition, the applicant stated that ACAR conductors, unlike aluminum conductor steel reinforced (ACSR) conductors, are not susceptible to environmental influences, such as SO_2 concentration in the air. When aluminum corrodes, it forms a protective oxide layer that protects the underlying material from further corrosion. When the steel core of an ACSR conductor loses its galvanized coating, it will continually corrode causing a decrease in ultimate strength. Therefore, the HCGS transmission conductors are not susceptible to the same corrosion phenomenon as ACSR transmission conductors.

The applicant stated that although the HCGS transmission conductors are not susceptible to same corrosion phenomenon as ACSR transmission conductors, in order to apply the findings from the Ontario Hydroelectric study of ACSR transmission conductors to the HCGS ACAR transmission conductors, it is postulated that the HCGS ACAR transmission conductors corrode at the same rate as comparable ACSR transmission conductors over 80 years. The applicant also stated that the study performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion. The Ontario Hydroelectric test did not include 2493 MCM 54/37 ACAR conductor. The Ontario Hydroelectric study did report, “The aluminum layers were found to have retained their original properties to a large degree. On the other hand the steel strands showed reductions in both tensile strength and the number of turns to failure.”

The applicant stated that the Ontario Hydroelectric study is considered to bound the HCGS configuration and corrosion rate because the aluminum alloy core is more corrosion resistant than galvanized steel. The example presented in the EPRI License Renewal Electrical Handbook, TR-1013475, (page 13-10) compares a 4/0 ACSR conductor to the results of the Ontario Hydroelectric Study. The applicant stated that the same comparison method is made here for the HCGS transmission conductor. Tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion. The ultimate strength and NESC design strength tension requirements of 2493 MCM 54/37 ACAR are 57,600 pounds and 34,560 pounds, respectively. The margin between the NESC design strength and the ultimate strength is 23,040 pounds. The applicant further stated that the Ontario Hydroelectric study showed a 30 percent loss of composite conductor strength in an 80-year-old conductor. In the case of the 2493 MCM ACAR transmission conductors, postulating a 30 percent loss of ultimate strength would mean that there would still be 5,760 pounds of margin between what is required by the NESC and the postulated 80-year ultimate conductor strength. The applicant then concluded that aging management activities regarding loss of conductor strength due to corrosion for HCGS transmission conductors are not required for the period of extended operation.

The applicant also stated that the switchyard bus and connections evaluated for HCGS are those credited for supplying power to in-scope components for recovery of offsite power following an SBO. The switchyard buses within the scope of this review are constructed of rigid 4-inch, schedule 80 aluminum pipe. The applicant also stated that switchyard buses at HCGS are connected to flexible conductors that do not normally vibrate and are supported by insulators and ultimately by static, structural components such as concrete footings and structural steel. Since there are no connections to moving or vibrating equipment, wind-induced abrasion and fatigue is not an applicable aging mechanism. The applicant further stated that the HCGS switchyard bus is not subject to an ocean environment or industrial air pollution. HCGS is located in a rural area, not near heavy industry that would provide a source for contaminants, and is not in close proximity to the Atlantic Ocean. The station is located at the end of the Delaware River (at the head of Delaware Bay), 50 miles from the Atlantic Ocean. Therefore, HCGS is not considered to be a seacoast plant, where salt spray is prevalent. Aluminum bus material does not experience any appreciable aging effects in this environment. Therefore, corrosion is not an applicable aging mechanism. The applicant also stated that switchyard bus connections employ good bolting practices consistent with the recommendations of EPRI 1003471, "Electrical Connector Application Guidelines." The connections are treated with corrosion inhibitors to avoid connection oxidation and torqued to avoid loss of preload, at the time of installation. The switchyard bus bolted connections are designed and installed using lock washers and stainless steel Belleville washers (not electroplated) that provide vibration absorption and prevent loss of preload. Therefore, the applicant concluded that oxidation and loss of preload are not applicable aging effects. The applicant further stated that transmission and distribution personnel perform normal maintenance activities on all portions of the switchyard, including transmission cable, switchyard bus, and connections. These maintenance activities have not revealed significant aging effects or mechanisms associated with this equipment to date.

The staff reviewed LRA Section 3.6.2.2.3 against the criteria in SRP-LR Section 3.6.2.2.3, which states that loss of material due to wind–induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload could occur in transmission conductors and connections, and in switchyard bus and connections. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that this aging effect is adequately managed.

The staff confirmed that switchyard buses at HCGS are connected to flexible conductors that do not swing and are supported by insulators and structural supports such as concrete footing and structural steel. Since there are no connections to moving or vibrating equipment, wind-induced abrasion and fatigue is not an applicable aging mechanism. The design of switchyard bolted connections at HCGS precludes torque relaxation and corrosion. The use of stainless steel Belleville washers is the industry standard to preclude torque relaxation. HCGS design incorporates the use of Belleville washers on bolted electrical connections of dissimilar metals to compensate for temperature changes, maintain the proper torque and prevent loosening. This method of assembly is consistent with the good bolting practices recommended by industry guidelines (EPRI TR-104213, "Bolted Joint Maintenance & Application Guide). The bolted connections and washers are coated with an anti-oxidant compound (a grease-type sealant) prior to tightening the connection to prevent the formation of oxides on the metal surface and to prevent moisture from entering the connection, thus reducing the chances of corrosion. This method of installation has been shown to provide a corrosion-resistant, low-electrical-resistance connection. The staff confirmed that the applicant's maintenance activities have not revealed significant aging effects or mechanisms associated with switchyard bus and connections to date. Based on the review, the staff determined that loss of material due to wind induced abrasion and fatigue, increased resistance of connection due to oxidation or loss of preload of switchyard bus and connections are not significant aging effects requiring management at HCGS.

The staff also noted that transmission conductors do not normally swing significantly. When transmission conductors swing due to a substantial wind, they do not continue to swing for very long once the wind has subsided. Wind loading that can cause a transmission line to sway is considered in design and installation. Furthermore, transmission conductors within the scope of license renewal are generally in short span, and the surface areas exposed to wind loads are not significant. The staff determined that loss of material that could result from wind–induced transmission conductor vibration or sway is not an applicable AERM.

The NESC sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which include consideration of ½ inch of radial ice and 4 pounds per square feet. The NESC requires that heavy load tension on installed conductors be less than 60 percent of the ultimate conductor strength. GALL AMR Table 3.6-1 does not have a specific line item dealing with ACAR transmission conductors. The staff noted that postulating a 30 percent loss of ultimate strength of an 80-year old ACAR conductor would mean that the ultimate conductor strength of this conductor would be 40,320 pounds (57600 x 0.7). The ratio between the heavy load tension and the ultimate conductor strength (based on the longest span on a transmission line (885 ft) would be approximately 57 percent (22,800 pounds/40,320 pounds). NESC requires the ratio between the heavy load tensions at 60 percent of the ultimate conductor strength. The postulated 80-year ultimate conductor strength would have enough margins to handle heavy load tension. The aluminum alloy core in ACAR transmission conductors is more corrosion resistant than the galvanized core steel in aluminum conductor steel reinforced (ACSR) transmission conductor. When aluminum corrodes, it forms a protective oxide layer that protects the underlying material from further corrosion. Furthermore, the applicant has confirmed that there is no operating experience with the transmission conductor to date. Based on this information, the staff determined that loss of material due to oxidization of ACAR transmission conductors at HCGS is not significant, and no aging management is required.

Based on the programs identified above, the staff concludes that the applicant has met the SRP-LR Section 3.6.2.2.3 criteria. For those line items that apply to LRA Section 3.6.2.2.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA program.

3.6.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Table 3.6.2-1, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Table 3.6.2-1, the applicant indicated, via Notes F through J that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how it will manage the aging effects.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is documented in the following section.

In LRA Tables 3.6.1 and 3.6.2-1 under “Fuse Holders,” the applicant indicated based on HCGS design and operating experience, aging effects and mechanisms are not applicable for HCGS fuse holders. The applicant also stated that the metallic clamp portion of in-scope fuse holders that are not part of a larger assembly are not subject to frequent manipulation or environment conditions that could result in aging effects. The applicant assigned Note I. Note I states that the aging effects in the GALL Report for this component, material, and environment combination are not applicable. The applicant stated in LRA Section 3.6.2.3 that at HCGS, there are eight electrical panels that contain only fuse holders and terminal blocks that are within the scope of license renewal and are not part of a larger assembly. Four fuse panels located inside the auxiliary building control or diesel generator area are in an electrical panel room. The environment inside the room is air-conditioned. The other four fuse panels are located inside the switchyard control building. The environment inside the switchyard control house is also air-conditioned. The applicant also stated that oxidation and corrosion are not a concern since the fuse holders are not located in or near humid areas. The applicant further stated that all of the fuse holders are protected from chemical contamination, and are within a mild environment inside a building. There are no sources of chemicals in the vicinity of electrical panels.

The applicant also stated that its walkdown of these enclosed electrical panels confirmed that the operating conditions for these holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation, or corrosion.

The applicant stated that fuse holders located in the auxiliary building control or diesel generator area are for 115-volt AC control power. The loads are instrumentation and control circuits that operate at low currents where no appreciate thermal cycling or ohmic heating occurs. The applicant also stated that the fuse holders located in the switchyard control house are for switchyard breaker DC control power. The normal supply of DC control power is from the battery charger. The battery is normally on a float charge, thus the fuses are lightly loaded with a small constant current. Therefore, the applicant stated that electrical and thermal cycling is not considered an applicable aging mechanism for these fuse holders. The applicant also stated that mechanical stress due to forces associated with electrical faults and transients are mitigated by the fast action of the circuit protective devices at high currents. Also, mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature.

The applicant stated that wear and fatigue is caused by repeated insertion and removal of fuses. The fuse in these fuse holders are not subject to frequent manipulation (i.e., removal and reinsertion) because they are neither clearance nor isolation points which support periodic testing nor preventive maintenance. The applicant also stated that these fuse holders are located in an electrical panel that is not mounted on moving or rotating equipment such as compressors, fans or pumps. Because the electrical panels are mounted with no attached sources of vibration, vibration is not an applicable aging mechanism. Therefore, the applicant concluded that the metallic clamps of these fuse holders will not exhibit the aging effect of fatigue due to mechanical stresses and/or frequent manipulation.

During the audit of the LRA during the week of February 16, 2010, the staff walked down these fuse holder panels and discussed them with the applicant technical staff. The staff confirmed that these fuse holders are installed in indoor air-controlled environments. The staff determined that the applicant has provided an adequate evaluation to support the conclusion that aging effect and mechanism as identified in the GALL Report, Volume 2, Revision 1, item VI.A-8 are not applicable to the fuse holders at HCGS. Mechanical stress resulting from electrical faults and transients is not considered a credible aging mechanism, since the events are infrequent and random in nature. Furthermore, stresses resulting from electrical faults are mitigated by fast acting circuit protective devices (etc., circuit breakers, fuses elements). The fuses are not routinely removed and reinserted to the metallic clamps. The fuses are only removed during fuse replacement with circuit isolation performed by circuit breakers in the circuit. Therefore, fatigue is not an applicable aging effect. The fuse panels are mounted on the wall and not on rotating machinery or in close proximity to rotating machines. Therefore, vibration is not an applicable aging effect. The fuse holders are located in a controlled air environment and are not exposed to fluid system leakage. Therefore, chemical contamination and corrosion is not an aging effect. These fuses are used in low voltage or low current application such that there is no significant ohmic heating. Ohmic heating and thermal cycling is not an applicable aging effect. The auxiliary room and switchyard control house are controlled air environments and oxidation of copper alloy fuse holder material is not expected in this environment. The staff walked down the enclosed electrical panels and confirmed that the operating conditions for these panels are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation, or corrosion. Therefore, the staff determined that aging affects and mechanisms identified in the GALL Report are not applicable to HCGS.

3.6.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the electrical and I&C components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.7 Conclusion for Aging Management Review Results

The staff reviewed the information in LRA Section 3, "Aging Management Review Results," and Appendix B, "Aging Management Programs." On the basis of its review of the AMR results and AMPs, the staff concludes that the applicant has demonstrated that the aging effects 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 reviewed the applicable UFSAR supplement program summaries and concludes that the UFSAR supplement adequately describes the AMPs credited for managing aging, as required by 10 CFR 54.21(d).

With regard to these matters, the staff concludes that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and any changes made to the CLB, in order to comply with 10 CFR 54.21(a)(3), are in accordance with NRC regulations.

SECTION 4

TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

This section of the safety evaluation report (SER) addresses the identification of time-limited aging analyses (TLAAs). In Sections 4.2 through 4.8 of the license renewal application (LRA), PSEG Nuclear, LLC (PSEG or the applicant) addressed the TLAAs for Hope Creek Generating Station (HCGS). SER Sections 4.2 through 4.8 document the review of the TLAAs conducted by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff).

TLAAs are certain plant-specific safety analyses that involve time-limited assumptions defined by the current operating term. Pursuant to Title 10, Section 54.21(c)(1), of the *Code of Federal Regulations* (10 CFR 54.21(c)(1)), an applicant must provide a list of TLAAs as defined in 10 CFR 54.3, “Definitions.”

In addition, pursuant to 10 CFR 54.21(c)(2), applicants must list existing plant-specific exemptions granted in accordance with 10 CFR 50.12, based on TLAAs. For any such exemption, the applicant must evaluate and justify the continuation of these exemptions for the period of extended operation.

4.1.1 Summary of Technical Information in the Application

To identify the TLAAs, the applicant evaluated calculations for HCGS against the six criteria specified in 10 CFR 54.3(a). The applicant prepared a list of potential generic TLAAs from NUREG-1800, Revision 1, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR), industry guidance, and operating experience. In addition, the applicant searched the current licensing basis (CLB) to confirm the existence of generic and plant-specific TLAAs. The CLB includes the following documents: updated final safety analysis report (UFSAR), operating license and license conditions, technical specifications (TSs), SERs, and licensing correspondence. The resulting list of potential TLAAs was reviewed against the six 10 CFR 54.3(a) criteria with the aid of design-basis documents, specifications, and calculations.

In LRA Table 4.1-1, “Time Limited Aging Analysis Applicable to HCGS,” the applicant listed the following applicable TLAAs:

- Neutron Embrittlement of the Reactor Pressure Vessel and Internals
    - neutron fluence
    - reactor pressure vessel materials upper-shelf energy reduction due to neutron embrittlement
    - adjusted reference temperature for reactor pressure vessel materials due to neutron embrittlement

  - reactor pressure vessel analyses: pressure-temperature limits
  - reactor pressure vessel circumferential weld examination relief
  - reactor pressure vessel axial weld failure probability
  - reactor pressure vessel core reflood thermal shock analysis
  - reactor internals components

- Metal Fatigue of the Reactor Pressure Vessel, Internals, and Reactor Coolant Pressure Boundary Piping and Components
  - reactor pressure vessel fatigue analyses
  - reactor pressure vessel internals fatigue analyses
  - reactor coolant pressure boundary piping and component fatigue analyses
  - non-Class 1 component fatigue analyses
  - effects of reactor coolant environment on fatigue life of components and piping (Generic Safety Issue-190)
- Environmental Qualification of Electrical Equipment
- Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses
  - fatigue analysis of primary containment, attached piping, and components
  - primary containment process penetrations and bellows fatigue analysis
  - vent line bellows
- Other Plant-Specific Time-Limited Aging Analyses
  - crane load cycle limit
  - refueling bellows fatigue
  - neutron fluence-induced bolt stress relaxation – jet pump auxiliary spring wedges and slip joint clamps

The applicant stated that it had identified no exemptions that were based on a TLAA that requires evaluation for continued use during the period of extended operation.

4.1.2 Staff Evaluation

The staff noted that the applicant's list of potential TLAAs was assembled using regulatory and industry documents and operating experience. The staff finds the applicant's use of these documents to compile a list of potential TLAAs reasonable because the applicant has used all available resources from the staff, the Nuclear Energy Institute (NEI), and past LRAs.

The applicant performed a review of its CLB in order to determine if the design or analysis feature of each potential TLAA in fact exists at HCGS and in its licensing basis and to identify additional potential plant-specific TLAAs in accordance with 10 CFR 54.3(a). The staff finds the applicant's approach in determining TLAAs reasonable because the applicant has performed a comprehensive search through its CLB, based on staff and industry guidance and operating experience, and has reviewed these potential TLAAs against the six criteria of a TLAA as defined in 10 CFR 54.3(a).

The staff confirmed that the applicant's LRA includes the TLAAs that are normally applicable to boiling-water reactor (BWR) applications. The staff finds the applicant's identification of the TLAAs in the LRA acceptable because they are consistent with the TLAAs identified in SRP-LR Sections 4.2, 4.3, 4.4, and 4.6 as being applicable to BWR LRAs.

The staff also verified that the LRA included the following additional plant-specific TLAAs:

- crane load cycle limit
- refueling bellows fatigue
- neutron fluence-induced stress relaxation – jet pump auxiliary spring wedges and slip joint clamps

The staff confirmed that the applicant's identification of these additional TLAAs satisfies the recommendations in SRP-LR Section 4.7 and are in accordance with the requirements of 10 CFR 54.3. The staff did not identify any omissions of TLAAs in the LRA.

The staff confirmed that the TLAAs identified by the applicant as being applicable to the LRA have been evaluated by the applicant against the provisions and criteria of 10 CFR 54.21(c)(1). The staff evaluated the TLAAs and provided its basis for acceptance in the staff evaluations provided in SER Sections 4.2, 4.3, 4.4, 4.5, 4.6, and 4.7.

Based on the information provided by the applicant as to the process it used to identify these exemptions and its results, the staff concludes, in accordance with 10 CFR 54.21(c)(2), there are no TLAA exemptions that the applicant must justify prior to entering into, and continuing through, the period of extended operation.

4.1.3 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable list of TLAAs, as required by 10 CFR 54.21(c)(1). The staff confirms, as required by 10 CFR 54.21(c)(2), that no exemption to 10 CFR 50.12 had been granted based on a TLAA.

4.2 Neutron Embrittlement of the Reactor Pressure Vessel and Internals

Neutron embrittlement describes changes in mechanical properties of reactor vessel (RV) materials caused by exposure to fast neutron flux (E>1.0 MeV) within the vicinity of the reactor core beltline region, i.e., the region that directly surrounds the active core. The most pronounced material change, relevant to this case, is a reduction in fracture toughness with increasing exposure to neutron flux. With additional exposure, the material's resistance to crack propagation, e.g., fracture toughness, decreases. Fracture toughness is also dependent on test temperature within the brittle to ductile transition region; as test temperature increases, the material's fracture toughness increases. The reference temperature for nil-ductility transition, RT_{NDT}, is an index temperature for the fracture toughness curve for a material. As neutron fluence on a material increases, the RT_{NDT} increases and, thus, higher temperatures are required for the material to remain ductile. This increased reference temperature is denoted as adjusted reference temperature (ART) and can be expressed by the equation

$ART = RT_{NDT} + \Delta RT_{NDT} + MT$

where:

ΔRT_{NDT} is the increase induced by the fluence exposure

MT is a margin term.

In addition to the increase in reference temperature, neutron embrittlement results in a decrease in the upper shelf energy, defined as the energy absorption level under fully ductile failure conditions.

Regulations governing RV integrity are found in 10 CFR Part 50. Specifically, 10 CFR 50.60 requires all light-water reactors to meet the fracture toughness, pressure-temperature (P-T) limits, and material surveillance program requirements for the reactor coolant pressure boundary (RCPB) pursuant to 10 CFR Part 50, Appendices G and H.

Determination of the projected RV reduction in fracture toughness as a function of neutron fluence affects several analyses that support HCGS operations:

- RPV materials upper-shelf energy (USE) reduction due to neutron embrittlement
- ART for RPV materials due to neutron embrittlement
- P-T limits
- RPV circumference weld examination relief
- RPV axial weld failure probability
- RPV core reflood thermal shock analysis
- reactor internal components

As extension of the operating period from 40 years to 60 years will increase neutron fluence, the 60-year fluence value and its impact upon the analyses that support operation are evaluated below.

4.2.1 Neutron Fluence

4.2.1.1 Summary of Technical Information in the Application

The applicant stated that the fluence was calculated using the actual power histories for cycles 1–14, and conservatively assumed the extended power uprate (EPU) power level for the remainder of the 60-year period with a plant capacity factor of 100 percent. This corresponds to an end-of-extended-license exposure of 56 effective full-power years (EFPY).

The applicant stated that the fluence values were calculated using the Radiation Analysis Modeling Application (RAMA) methodology[5] which was approved by the staff in an SER dated May 13, 2005 (ML051380572), based on its adherence to Regulatory Guide (RG) 1.190. The applicant also stated that the HCGS fluence analysis complies with the conditions of the RAMA SER.

4.2.1.2 Staff Evaluation

The RAMA methodology was reviewed by the staff and found acceptable because the calculational method, uncertainty, and qualification were found to adhere to the guidance contained in RG 1.190. Therefore, fluence analyses performed using the RAMA methodology adhere to the guidance contained in RG 1.190.

In its SER approving the RAMA methodology, the staff included a condition. The condition stated that the RAMA methodology needed to be qualified using plant-specific dosimetry comparisons for any given BWR geometry. The initial qualification of the RAMA methodology was based on dosimetry comparisons to plants of the BWR/4 design, and HCGS was one of the plants against which the RAMA methodology was qualified. The RAMA methodology is, therefore, acceptably qualified not only for plants of the BWR/4 design, but also specifically based on HCGS capsule dosimetry. Therefore, the staff confirmed that the applicant's fluence calculations comply with the conditions of the RAMA SER. Because the applicant's fluence analysis meets the condition set forth in the staff's SER approving the RAMA methodology and because the analysis was performed using the RAMA methodology, the staff finds that the applicant's fluence analysis adheres to the guidance set forth in RG 1.190 and is, hence, acceptable.

The applicant used a 100 percent capacity factor and evaluated fluences to 56 EFPY of exposure. This is acceptable and conservative because it will not be possible for the plant to operate at a 100 percent capacity factor through the end of extended license. Reductions in capacity factor will result from required refueling and maintenance outages and at times when the plant is unable to operate at its licensed power level.

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[5] The RAMA methodology is described in the following documents: (1) "BWR Vessel and Internals Project, RAMA Fluence Methodology Manual," BWRVIP-114, June 11, 2003 (ML031640195); (2) "RAMA Fluence Methodology Benchmark Manual-Evaluation of Regulatory Guide 1.190 Benchmark Problems," BWRVIP-115, June 26, 2003 (ML031820254); and (3) "RAMA Fluence Methodology - Susquehanna Unit 2 Surveillance Capsule Fluence Evaluation for Cycles 1-5," BWRVIP-117, August 5, 2003 (ML03230320).

The staff finds, in consideration of the items discussed above, that the peak fluence values identified by the applicant are acceptable due to the conservative nature of the 56 EFPY calculation and due to the calculational method's adherence to the guidance contained in RG 1.190.

4.2.1.3 UFSAR Supplement

LRA Section A.4.2 provides the UFSAR supplement for the neutron fluence analysis TLAA evaluation. Based on its review of the UFSAR supplement, the staff concludes that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d), and consistent with SRP-LR Section 4.2.3.2.

4.2.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that for RV neutron fluence, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and is, therefore, acceptable.

4.2.2 Reactor Pressure Vessel Materials Upper-Shelf Energy Reduction Due to Neutron Embrittlement

4.2.2.1 Summary of Technical Information in the Application

LRA Section 4.2.1 presents the applicant's evaluation of Charpy USE values for the period of extended operation. The applicant stated that the HCGS CLB analyses evaluated reduction of fracture toughness of the RPV for 40 years and is a TLAA. The RPV neutron embrittlement TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

The USE values are required to be at least 50 feet-pounds (ft-lb) for the life of the RPV including the period of extended operation. Specifically, 10 CFR Part 50, Appendix G requires that USE values for all RPV materials include the effects of neutron radiation and that the USE values at the one quarter thickness (¼ T) of the RPV wall location for the beltline materials, including plates, welds, and nozzles, be maintained at no less than 50 ft-lb for the life of the RPV. Calculated neutron fluence values, considering the extended operation to 56 EFPY, are used to project changes in USE values for the period of extended operation, per 10 CFR Part 50, Appendix G. RG 1.99, Revision 2 is used to calculate the projected USE values.

The applicant stated that all plates and welds meet the 50 ft-lb criterion at 56 EFPY, as seen in LRA Table 4.2.1-1.

4.2.2.2 Staff Evaluation

The staff reviewed LRA Section 4.2.1 to verify, pursuant to 10 CFR 54.21(c)(1)(ii), that the USE values have been projected to the end of the period of extended operation. According to RG 1.99, Revision 2, the predicted decrease in USE values due to neutron irradiation during plant operation is dependent upon the amount of copper in a given material and the predicted neutron fluence on the given material. RG 1.99, Revision 2 includes two different methods for calculating the predicted decrease in USE values:

- For materials that have less than two sets of credible surveillance data, the RG recommends Position 1.2.
- For those cases when there are at least two sets of credible surveillance data, the RG recommends Position 2.2.

The staff noted that for a conventional USE evaluation per RG 1.99, Revision 2, the unirradiated USE value is needed to calculate the decrease in USE due to irradiation. Transverse plate values for unirradiated USE were conservatively estimated as described in the UFSAR supplement. For the welds, the unirradiated USE values were assumed to be equal to the measured values at 10 °F. The staff has determined that the use of these values was acceptable.

The staff also performed independent calculations and confirmed that the applicant's projected USE values are conservative. In all cases, the beltline materials will have a projected USE at or above 50 ft-lb for 56 EFPY. For the limiting plate, weld, and nozzle materials, the projected USE values are 66.4, 60.2, and 62.6 ft-lb, respectively. Thus, the materials will meet the requirements of 10 CFR Part 50, Appendix G for 56 EFPY.

4.2.2.3 UFSAR Supplement

LRA Section A.4.2.1 provides the UFSAR supplement for the RPV materials USE reduction due to neutron embrittlement TLAA evaluation. The staff reviewed this UFSAR supplement description of the calculation and notes that it conforms to the recommended description for this type of program as described in SRP-LR Section 4.2.2.1.1.2. Based on its review of the UFSAR supplement, the staff concludes that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

4.2.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that all of the HCGS RPV beltline materials will have USE at the ¼ T location of at least 50 ft-lb throughout the period of extended operation (through 56 EFPY), which meets the 10 CFR Part 50, Appendix G USE requirement. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and is, therefore, acceptable.

4.2.3 Adjusted Reference Temperature for Reactor Pressure Vessel Materials Due to Neutron Embrittlement

4.2.3.1 Summary of Technical Information in the Application

The effects of neutron radiation on RT_{NDT} are reflected in the adjusted reference temperature (ART). Which is calculated by adding ΔRT_{NDT} to initial RT_{NDT} with an appropriate margin for uncertainties. The applicant stated that the ΔRT_{NDT} values for the RPV beltline plates and welds were projected to 56 EFPY using the methods described in RG 1.99, Revision 2 so that the ART values could be revised to reflect the neutron exposure expected for the end of the period of extended operation. The applicant reviewed data from the NRC Reactor Vessel Integrity Database (RVID) and the Boiling Water Reactor Vessel and Internals Program (BWRVIP) Integrated Surveillance Program (ISP) and used the highest limiting material property values in computations of ΔRT_{NDT} and ART for conservative results. The results are shown in LRA Table 4.2.2-1. The applicant dispositioned this TLAA for ART in accordance with 10 CFR 54.21(c)(1)(ii).

4.2.3.2 Staff Evaluation

The staff reviewed LRA Section 4.2.2 to verify, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation. The applicant calculated the ΔRT_{NDT} and ART values based on the 56-EFPY neutron fluence for the RPV beltline materials as indicated in LRA Table 4.2.2-1. The staff performed independent calculations for comparison to those from the applicant. In each case, the applicant reports the same or a more conservative ΔRT_{NDT} value than that determined in the staff's calculations, and all of the ART values are developed in accordance with regulatory guidelines. Therefore, the staff finds the applicant has demonstrated that the analyses have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.2.3.3 UFSAR Supplement

LRA Section A.4.2.2 provides the UFSAR supplement for the ART for RPV materials due to neutron embrittlement TLAA evaluation. Based on its review of the UFSAR supplement, the staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d) and consistent with SRP-LR Section 4.2.3.2.

4.2.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated that the ART analyses have been projected to the end of the period of extended operation in a manner consistent with 10 CFR 54.21(c)(1)(ii). The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and is, therefore, acceptable.

4.2.4 Reactor Pressure Vessel Analyses: Pressure-Temperature Limits

4.2.4.1 Summary of Technical Information in the Application

LRA Section 4.2.3 summarizes the evaluation of P-T limits for the period of extended operation. The HCGS TSs contain P-T curves that are valid through 32 EFPY. Revised P-T limits are not required at this time, but will continue to be updated, as required by 10 CFR Part 50, Appendix G, consistent with TLAA management in accordance with 10 CFR 54.21(c)(1)(iii).

4.2.4.2 Staff Evaluation

The staff reviewed LRA Section 4.2.3 to verify that the applicant's analyses for the P-T curves have been developed in compliance with the requirements specified in 10 CFR Part 50, Appendix G.

The staff noted that the current P-T limits, valid for operation up to 32 EFPY, were approved by the staff on November 1, 2004, and accounts for the change in neutron flux associated with operations under EPU conditions. The staff agrees that revised P-T limits are not required at this time. The staff notes that the applicant has committed to update the P-T curves as needed to assure that operational limits remain valid through the period of extended operation (Commitment No. 48). Therefore, the staff finds that the applicant's plan to manage the P-T limits in accordance with 10 CFR 54.21(c)(1)(iii) is acceptable, because the applicant will implement changes to the P-T limit curves through the license amendment process (i.e., through revision of the plant TSs) and, thus, meet the requirements of 10 CFR 50.60 and 10 CFR Part 50, Appendix G.

4.2.4.3 UFSAR Supplement

LRA Section A.4.2.3 provides the UFSAR supplement for the P-T limits TLAA evaluation. Based on its review of the UFSAR supplement, the staff concludes that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d), and consistent with SRP-LR Section 4.2.2.1.3.3.

4.2.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for P-T limits, the effects of aging on the intended function will be adequately managed for the period of extended operation. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR 4.2.2.1.3.3. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and, therefore, is acceptable.

4.2.5 Reactor Pressure Vessel Circumferential Weld Examination Relief

4.2.5.1 Summary of Technical Information in the Application

LRA Section 4.2.4 summarizes the issues that govern inspection of the RPV circumferential welds at HCGS. The circumferential welds are required to be inspected at regular intervals described in Table IWB-2500-1, Examination Category B-A of ASME Code Section XI. HCGS has received inspection relief for the circumferential welds for the remaining initial licensed period of operation in an NRC letter dated November 1, 1999. The basis for this relief request was an analysis that satisfied the limiting conditional probability of failure (PoF) for the circumferential welds at the expiration of the current license, based on BWRVIP-05, "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations," and the extent of neutron embrittlement expected through 40 years of operation.

The analysis in LRA Section 4.2.4 uses the PoF and the mean ART (MART)[6] for the limiting beltline circumferential weld to characterize the anticipated metallurgical effects due to increased fluence expected for 56 EFPY. The PoF for the beltline circumferential welds due to a limiting event at HCGS, 4.10×10^{-8}, is less than the PoF value for the Chicago Bridge and Iron (CB&I) reference plant, 1.78×10^{-5}, in Table 2.6-5 of the SER of BWRVIP-05, "Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report," July 28, 1998. The MART value at 56 EFPY (9.4 °F) is bounded by the 64 EFPY MART value provided by the staff for the CB&I weld (70.6 °F). Taken together, the PoF and MART analyses justify the elimination of the RPV circumferential volumetric weld examination in the vessel beltline region to the end of the period of extended operation (56 EFPY).

In LRA Section 4.2.4, the applicant also stated that the procedures and training used to limit RPV cold overpressure events will be the same as those approved by the staff when HCGS requested the BWRVIP-05 technical alternative be used for the current license period.

In LRA Section A.5, Commitment No. 49, the applicant stated that it will request relief from the requirement to perform volumetric examinations of the RPV circumferential welds, in accordance with 10 CFR 50.55a, prior to the period of extended operation. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(ii).

4.2.5.2 Staff Evaluation

The staff reviewed LRA Section 4.2.4 to verify, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses to support the relief from the ASME Code Section XI inservice inspection (ISI) of circumferential welds have been projected to the end of the period of extended operation. The technical basis for the applicant's alternative is found in the staff's SER of the BWRVIP-05 report.

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[6] MART is defined as the RT_{NDT} value for the unirradiated material added to a ΔRT_{NDT} value that reflects the peak neutron fluence for the limiting weld at the end of extended period of operation. There is no margin term used in calculating the value of MART.

The SER indicated that BWR applicants may request relief from ISI requirements of 10 CFR 50.55a(g) for volumetric examination of circumferential RPV welds by demonstrating:

(1) At the expiration of the license, the limiting conditional PoF for circumferential welds in the evaluation must be 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 core damage frequency (CDF) of any BWR plant.

(2) The applicant must implement operator training and establish procedures that limit the frequency of cold overpressure events to the amount specified in the report.

The first criterion is addressed in LRA Table 4.2-7 where the applicant has summarized the effects of irradiation on the limiting axial weld at HCGS and compared its properties to the NRC limiting CB&I circumferential weld used in the July 28, 1998, SER for BWRVIP-05. The staff notes that the HCGS circumferential weld has a lower copper and nickel content, as well as a lower neutron fluence at the clad/base metal interface than the limiting CB&I vessel circumferential weld. The unirradiated RT_{NDT} is higher for the HCGS circumferential weld, but overall, the effects of chemistry and neutron fluence contribute to lower the MART for the HCGS circumferential weld when compared to the limiting CB&I vessel circumferential weld. The staff confirmed that the limiting HCGS circumferential weld is less susceptible to irradiation damage than the NRC limiting plant-specific case. Therefore, the applicant's evaluation is acceptable.

For the second criterion, the applicant stated in LRA Section 4.2.4 that HCGS will use the same procedures and training to the period of extended operation in the same manner that has been the practice during the original licensing period. Based on this, the staff determines that continued implementation of operator training and establishment of procedures limiting the frequency of cold overpressure events meets the criterion in the July 28, 1998, SER for BWRVIP-05. The staff determines that this condition concerns specific plant operation procedures and is not considered a TLAA.

The staff finds the applicant's conclusion for this TLAA acceptable because: (1) the staff's evaluation, based on LRA Section 4.2.4, indicates that the conditional failure probability after 56 EFPY for the RPV circumferential welds is bounded by the staff analysis in the July 28, 1998 SER for BWRVIP-05; and (2) the applicant will request relief (Commitment No. 49) from the requirement to perform volumetric examinations of the RPV circumferential welds, in accordance with 10 CFR 50.55a, prior to entering the period of extended operation.

4.2.5.3 UFSAR Supplement

LRA Section A.4.2.4 includes the applicant's UFSAR supplement summary description of its TLAA evaluation for relief from RPV circumferential weld examination. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR 4.2.2.1.4. Based on its review of the UFSAR supplement, the staff concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), for RPV circumferential weld examination relief that the analysis has been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and, therefore, is acceptable.

4.2.6 Reactor Pressure Vessel Axial Weld Failure Probability

4.2.6.1 Summary of Technical Information in the Application

LRA Section 4.2.5 summarizes the evaluation of RPV axial weld failure probability for the period of extended operation. The SER for BWRVIP-74, "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," evaluated the failure frequency of BWR RPV axial welds and determined it to be below 5.0×10^{-6} per reactor year for the first 40 years of reactor operation. Applicants for license renewal must evaluate RPV axial welds to show that their failure frequency remains below the 5.0×10^{-6} per reactor year calculated in the SER for BWRVIP-74. The SER states that an acceptable justification is that the MART for the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in the SER. The value of MART for the limiting axial weld at HCGS after 56 EFPY is projected to be 14.3 °F, well below the generic value of 117.1 °F for CB&I axial welds that is found in the SER for BWRVIP-05, and thus the PoF for the limiting axial weld is well below the acceptable limit of 5.0×10^{-6} per reactor year. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(ii).

4.2.6.2 Staff Evaluation

The staff has reviewed LRA Section 4.2.5 to verify, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses for the RPV axial welds have been projected to the end of the period of extended operation.

In LRA Table 4.2.5-1, the applicant summarized the effects of irradiation on the limiting axial weld at HCGS and compared its properties to the NRC limiting CB&I axial weld used in the July 28, 1998, SER for BWRVIP-05. The staff notes that the HCGS weld has a lower copper and nickel content, as well as a lower neutron fluence at the clad/base metal interface than the limiting CB&I vessel axial weld; the two welds have the same unirradiated RT_{NDT}. The staff concludes that the HCGS axial welds are less susceptible to irradiation damage than the NRC limiting CB&I axial weld; therefore, the applicant's evaluation is acceptable. In addition, the principle of warm prestress provides assurance that brittle fracture of the HCGS RPV will not occur as the applied stress intensity factor recedes from its maximum value, at lower temperatures.

4.2.6.3 UFSAR Supplement

LRA Section A.4.2.5 provides the UFSAR supplement for the RPV axial weld PoF TLAA evaluation. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in

SRP-LR 4.2.2.1.5. The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

4.2.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that for RPV axial weld PoF, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and, therefore, is acceptable.

4.2.7 Reactor Pressure Vessel Core Reflood Thermal Shock Analysis

4.2.7.1 Summary of Technical Information in the Application

In LRA Section 4.2.6, the applicant addressed thermal shock on the RPV by re-evaluating a similar BWR-6 analysis, “Fracture Mechanics Evaluation of a Boiling Water Reactor Vessel Following a Postulated Loss of Coolant Accident, August 1979,” with the HCGS-specific wall thickness. The new analysis referenced in the LRA showed that at the temperature where the applied stress intensity factor from the analysis was a maximum, 100 ksi-in$^{1/2}$, the fracture toughness of the limiting beltline material (plate 5K3025/1) after 56 EFPY of service would be 200 ksi-in$^{1/2}$. Therefore, for the period of extended operation (56 EFPY), brittle fracture of the HCGS RPV is unlikely due to the thermal shock that could occur in the case of a reflood following a design-basis loss of coolant accident (LOCA) during operation.

4.2.7.2 Staff Evaluation

The staff reviewed LRA Section 4.2.6 to verify, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation.

The staff reviewed LRA Sections 4.2.2 and 4.2.6 to verify the fracture toughness for the limiting beltline material. The staff noted that the input data used in the re-evaluation of the core reflood thermal shock analysis was consistent with the projected Charpy impact properties at 56 EFPY. The peak applied stress intensity used in the calculation is similar to that found in the thermal shock calculations done by Dickson and Kirk in the 2004 ASME Pressure Vessel and Piping conference paper “Assessment of Large-Scale Pressurized Thermal Shock Experiments Using the FAVOR Fracture Mechanics Computer Code.” The staff also noted that because the RPV wall thickness is a major parameter in determining stresses due to thermal shock, it was reasonable to assume that the slightly thicker HCGS RPV will have a peak stress intensity factor at the ¼ T location that is above the 100 ksi-in$^{1/2}$ value quoted for the BWR-6, but the increase is minor. The existing margin between the material property and the applied stress intensity factor is significant enough to assure safe operation. Based on the wide margin between the projected fracture toughness value and the estimated applied stress intensity factor, the staff determined that brittle fracture of the HCGS RPV is unlikely due to reflood thermal shock following a design-basis LOCA during the period of extended operation.

4.2.7.3 UFSAR Supplement

LRA Section A.4.2.6 provides the UFSAR supplement for the RPV core reflood thermal shock analysis TLAA evaluation. Based on its review of the UFSAR supplement, the staff concludes that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d) and consistent with SRP-LR Section 4.2.3.2.

4.2.7.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that for the RPV core reflood thermal shock analysis, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and, therefore, is acceptable.

4.2.8 Reactor Internals Components

4.2.8.1 Summary of Technical Information in the Application

In LRA Section 4.2.7, the applicant stated that the core plate rim holddown bolts can experience stress relaxation due to the high neutron fluence in the core of the reactor. An initial plant-specific analysis performed in association with the EPU at HCGS showed that there was no concern with radiation-induced loss of preload on the core plate rim holddown bolts up to 56 EFPY. A revised analysis with updated neutron fluence values for exposure up to 56 EFPY showed the preload on the core plate rim holddown bolts was adequate only up to 43.9 EFPY. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(iii).

Before entering the period of extended operation, the applicant committed (Commitment No. 51) to either: (1) install core plate wedges to retain the safety function of the core plate, or (2) show by analysis that the component function is maintained.

4.2.8.2 Staff Evaluation

The staff reviewed LRA Section 4.2.7 to verify, pursuant to 10 CFR 54.21(c)(1)(iii), that the aging effects on the core plate rim holddown bolts will be managed to the end of the period of extended operation.

The staff reviewed LRA Section 4.2.7 and compared the HCGS evaluation with the operating experience at other BWRs in the United States. The staff noted that the installation of the wedges prevents lateral motion of the core plate and removes the requirement to inspect the core plate rim holddown bolts; BWR/6 plants already use core plate wedges to replace the structural function of the bolts.

The staff noted that the applicant committed (Commitment No. 51) to implement the following prior to the period of extended operation: (1) install core plate wedges to retain the safety function of the core plate, or (2) show by analysis that the component function is maintained.

Based on industry experience, the staff considers the applicant’s commitment an acceptable method to manage the effects of loss of preload in the core plate rim holddown bolts.

4.2.8.3 UFSAR Supplement

LRA Section A.4.2.7 provides the UFSAR supplement for the reactor internal components TLAA evaluation. The staff also notes that the applicant committed (Commitment No. 51) to perform one of the following prior to the period of extended operation: (1) install core plate wedges, or (2) perform an analysis that demonstrates the component function is maintained.

Based on its review of the UFSAR supplement, the staff concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d) and consistent with SRP-LR Section 4.2.3.2.

4.2.8.4 Conclusion

On the basis of its review of LRA Section 4.2.7 and industry experience, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that for the core plate rim holddown bolts, the effects of aging on the intended function will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and therefore, is acceptable.

4.3 Metal Fatigue of the Reactor Pressure Vessel, Internals, and Reactor Coolant Pressure Boundary Piping and Components

The applicant provided its assessment of those analyses in the CLB that comprise metal fatigue for the facility and are TLAAs in Section 4.3. The applicant divides this section of the LRA into the following subsections:

- LRA Section 4.3.1, “Reactor Pressure Vessel Fatigue Analyses”
- LRA Section 4.3.2, “Reactor Pressure Vessel Internals Fatigue Analyses”
- LRA Section 4.3.3, “Reactor Coolant Pressure Boundary Piping and Component Fatigue Analyses”
- LRA Section 4.3.4, “Non-Class 1 Component Fatigue Analyses”
- LRA Section 4.3.5, “Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping (Generic Safety Issue 190)”

The staff evaluates the TLAAs contained in the LRA in the subsections that follow.

4.3.1 Reactor Pressure Vessel Fatigue Analyses

4.3.1.1 Summary of Technical Information in the Application

LRA Section 4.3.1 summarizes the evaluation of the RPV fatigue analyses for the period of extended operation. This TLAA is based on the analysis in UFSAR Section 3.9. In this TLAA, the applicant stated that the metal fatigue evaluation was performed for the RPV and its components, including the vessel support skirt, shell, upper and lower heads, closure flanges and studs, nozzles and penetrations, nozzle safe ends, and refueling bellows support. The applicant also stated that these components were designed in accordance with ASME B&PV Code, Section III and, therefore, were subject to fatigue analyses. The applicant further stated that these analyses were based upon the number of thermal and pressure transients described in UFSAR Tables 3.9-1 and 3.9-1a and summarized in LRA Table 4.3.1-1. The applicant compiled the number of transients experienced at HCGS from initial plant startup up to December 31, 2007, using the HCGS Cycle Counting Program. Based on this data, the applicant derived the 60-year projected number of cycles and compared these values to design-basis number of cycles. The applicant addresses this TLAA for RPV fatigue analyses based on the criterion in 10 CFR 54.21(c)(1)(iii), in which the applicant demonstrates that the effects of aging associated with the analysis will be adequately managed for the period of extended operation using the Metal Fatigue of Reactor Coolant Pressure Boundary Program to monitor the numbers of cycles of the design transients, and the corresponding CUF for critical RPV components.

4.3.1.2 Staff Evaluation

The staff reviewed the TLAAs in LRA Section 4.3.1 for RPV fatigue analyses against the criteria in SRP-LR Section 4.3.2.1.1.3 and review procedures in SRP-LR Section 4.3.3.1.1.3 in order to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the RPV intended functions will be adequately managed for the period of extended operation.

The staff also reviewed the following additional documents that are relevant to the staff's evaluation of this TLAA:

- TS 5.7, "Component Cyclic or Transient Limit"
- UFSAR Section 3.9, "Mechanical Systems and Components"
- UFSAR Table 3.9-1, "Plant Events"
- UFSAR Table 3.9-1a, "Plant Events – Feedwater Nozzles"
- 10 CFR 50.55a, "Codes and Standards"

The staff reviewed the information summarized in LRA Table 4.3.1-1 and UFSAR Tables 3.9-1 and 3.9-1a. The staff determined that the transients and the number of cycles specified in UFSAR Table 3.9-1 were used in fatigue analyses of the RPV and its components with exception of the feedwater nozzles analyses; whereas the transients and the number of cycles specified in UFSAR Table 3.9-1a were used in fatigue analyses of feedwater nozzles. The staff further determined that, for the same transients, the number of cycles used in the feedwater analyses are more limiting than those used in the analyses of the RPV and its other components. Because the applicant included a more limiting value for the numbers of cycles to be monitored under the Metal Fatigue of Reactor Coolant Pressure Boundary Program into LRA Table 4.3.1-1, the staff concluded that the methodology used to derive the allowable number of cycles is appropriate.

From LRA Table 4.3.1-1, the staff noted that the limiting number of cycles for loss of feedwater heaters (turbine trip with 100 percent steam bypass and partial feedwater heater bypass) is 23 cycles. In UFSAR Table 3.9-1a, the loss of feedwater heaters transient is separated into two transients of turbine trip with 100 percent steam bypass and with partial feedwater heater bypass, with 3 cycles and 20 cycles, respectively.

By letter dated June 25, 2010, the staff issued RAI 4.3-01. Part 1 requested the applicant to clarify whether, in the fatigue analyses for the feedwater nozzles, the loss of feedwater heaters transients: (1) were accounted for as two separate transients and (2) should be included in the Metal Fatigue of Reactor Coolant Pressure Boundary Program as two transients with 3 and 20 limiting numbers of cycles.

In its response dated July 22, 2010, the applicant responded to RAI 4.3-01, Part 1. By letter dated September 20, 2010, the applicant amended its response to RAI 4.3-01, Part 1. The applicant stated in the fatigue analyses for the feedwater nozzles, the turbine trip with 100 percent steam bypass, and the partial feedwater heater bypass were accounted for as two separate transients. The applicant further stated that these transients are included in the Metal Fatigue of Reactor Coolant Pressure Boundary Program and are counted as two separate transients per the current design basis. The applicant stated that the number of design-basis cycles does not represent a design limit and that the fatigue usage for a component is normally the result of several different thermal and pressure transients. Therefore, exceeding the number of cycles for one transient does not necessarily imply the fatigue usage factor will exceed an acceptance limit. The applicant clarified that the two transients will not have limits set for them, since the calculated fatigue cumulative usage factor will be the limiting value and is monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The staff noted that the applicant's method of monitoring the feedwater nozzle ensures the design code limit of 1 is not exceeded. The applicant further stated that due to the staff's concerns with the fatigue monitoring program confirmatory evaluation performed to address RIS 2008-30, stress-based fatigue monitoring will not be used at this time. Furthermore, the applicant will only use cycle-based fatigue monitoring. The applicant stated that cycle-based fatigue monitoring uses the design-basis fatigue calculations which consider the six stress terms in accordance with the methodology from ASME Code Section III, Subsection NB, Subarticle NB-3200 for the RPV components.

Based on its review, the staff finds the applicant's response, as amended, to RAI 4.3-01, Part 1 acceptable because the applicant clarified that the fatigue analyses for the feedwater nozzle account for the turbine trip with 100 percent steam bypass and with partial feedwater heater bypass transients, separately. In addition, the applicant will manage the effects of aging with its Metal Fatigue of Reactor Coolant Pressure Boundary Program to ensure the design code limit of 1 is not exceeded. The staff's concern described in RAI 4.3-01, Part 1 is resolved.

The staff reviewed LRA Table 4.3.1-1, which states that the limiting number of cycles for scram (turbine generator trip, feedwater on, isolation valves stay open, and all other scrams) is 136 cycles. In UFSAR Table 3.9-1, the scram transient is separated into two transients for turbine generator trip, feedwater on, isolation valves stay open, and other scrams with 40 cycles and 140 cycles, respectively.

By letter dated June 25, 2010, the staff issued RAI 4.3-01, Part 2 requesting that the applicant clarify whether scram transients: (1) were accounted for in the fatigue analyses for the RPV and its components, scrams transients were accounted for as two separate transients; and (2) should be included into the Metal Fatigue of Reactor Coolant Pressure Boundary Program as two transients.

In its response to RAI 4.3-01, Part 2, dated July 22, 2010, the applicant stated: (1) the fatigue analyses for all the RV component locations, listed in LRA Table 4.3.1-2, other than the feedwater nozzle locations, combine the two transients (turbine generator trip, feedwater on, isolation valves stay open, and all other scrams); and (2) the two scram transients are included in the Metal Fatigue of Reactor Coolant Pressure Boundary Program. These two scram transients are combined by the fatigue monitoring software and used to compute fatigue usage for the RV component locations listed in LRA Table 4.3.1-2, other than the feedwater nozzle locations. The staff noted that since the applicant's fatigue analyses for all the RV component locations other than the feedwater nozzle locations combined these two transients, it is reasonable that the applicant also counts these two transients together.

Based on its review, the staff finds the applicant's response to RAI 4.3-01, Part 2 acceptable because: (1) the applicant clarified that the fatigue analyses for all the RV component locations other than the feedwater nozzle locations combine the two transients (turbine generator trip, feedwater on, isolation valves stay open, and all other scrams), and (2) these transients are appropriately monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program to ensure the assumptions in the fatigue analyses are not exceeded. The staff's concern described in RAI 4.3-01, Part 2 is resolved.

The staff reviewed the applicant's cycle projection methodology in LRA Section 4.3.1 for acceptability. The staff noted that the actual 60-year transient projection data that the applicant provided compared the design-basis transients to the design-basis limits for these transients in LRA Table 4.3.1-1 to determine whether the applicant had provided an acceptable basis for accepting these metal fatigue TLAAs.

During its review, the staff noted that the applicant's 60-year cycle projections are based on the number of transients experienced at HCGS from initial plant startup up to December 31, 2007, and the trends from the past 12 years of plant operation. However, LRA Section 4.3.1 does not provide sufficient information for the staff to conclude that the projection methodology used by the applicant is acceptable and would produce conservative values for 40- and 60-year cycle projections.

By letter dated June 25, 2010, the staff issued RAI 4.3-02 requesting that the applicant provide: (1) additional information for all monitored transients on the number of cycles occurred during the last 12 years of plant operation, and (2) the technical basis for the assumption used that cycle accumulation trends during the period of extended operation will remain equal to or less than the trend over the last 12 years of plant operation.

In its response dated July 22, 2010, the applicant stated that it has been tracking those transients required by the TSs, since initial operations of the unit commenced. The applicant further stated that Enhancement 1 for the Metal Fatigue of Reactor Coolant Pressure Boundary Program is being made to add transients to the program beyond those defined in the TSs. The staff noted that those transients added to the program include the design-basis transients necessary to monitor those components determined to be within the scope of license renewal and have a cumulative fatigue usage TLAA. The staff further noted that for those transients not included in the applicant's TSs, the applicant has the accumulated number of cycles as of December 31, 2007. The staff noted that the accumulation trends during the last twelve years of operation used in the 60-year transient projections are based on data from the present cycle counting program and are supplemented by retrieval of plant data and operating history to determine a conservative cycle count for transients in the applicant's TSs and those transients associated with Enhancement 1 of the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

The applicant also provided in its response the method to obtain the 60-year projected number of cycles. The staff noted that this methodology involved obtaining the average rate of occurrence for each transient that will require monitoring over a 12-year period (1995–2007) to determine the number of cycles that will occur from 2007 until 2026 (end of initial license) and 2046 (end of renewed license). The staff further noted that this projected accumulation was summed with the number of cycles accrued as of December 31, 2007. The staff noted that this 12-year period provides data that indicates changes in operation have been considered in making projections for 60 years of operation. Specifically, the applicant stated that a review of the operating history (e.g., unit capacity factor) during these 12 years as compared to that of previous years shows increases in capacity factor during the last 12 years when compared to the first nine years. The applicant attributes this increased capacity factor to improvements that have been made in operation, maintenance, and equipment reliability through company and industry improvement initiatives. The staff finds the applicant's approach to determine the 40-year and 60-year projections and use of the 12-year trending period reasonable because it is based on data from (1) actual cycle counting since initial plant operation or retrieval of plant data, and (2) recent operating history, (last 12 years) which indicates increased plant reliability due to improvements in operation, maintenance, and equipment reliability over time and have decreased the rate of occurrence for plant transients.

The staff noted the 60-year transient projections are representative of what is expected based on the transients experienced during the last 12 years, but these projections do not replace the Metal Fatigue of Reactor Coolant Pressure Boundary Program implementing procedures which will include monitoring these transients to compute the cumulative usage factor (CUF). The staff further noted that the applicant's program will monitor the numbers of cycles of the design transients, and the corresponding CUF for critical RPV components will be tracked to ensure that it remains less than the allowable limit.

The applicant stated that assumptions were included to provide a conservative basis for accumulation trends during the last 12 years. Furthermore, examples of these assumptions include: (1) additional cycles were assumed when a degree of uncertainty existed; (2) additional cycles were assumed when no cycles were found during the last 12 years of operation for a given transient; and (3) additional cycles were added to injection transients, whose rate of occurrence may be affected by EPU. The staff noted that the applicant's assumptions and 60-year number of cycles assumed for analysis in LRA Table 4.3.1-1 are reasonable because it considers the possibility of the transients occurring in future years, even though no or few cycles had occurred during the last 12 years of operation.

Based on its review, the staff finds the applicant's response to RAI 4.3-02 acceptable because: (1) the applicant confirmed it has been tracking transients since initial plant operation, as required by its TSs; (2) the applicant's 60-year transient projections are based on data from the present cycle counting program and supplemented by retrieval of plant data and operating history; (3) the applicant included assumptions for additional cycles in its 60-year projections as described above; and (4) the applicant considered the possibility of the transients occurring in the future, even though no or few cycles had occurred during the last 12 years of operation. The staff's concern described in RAI 4.3-02 is resolved.

The applicant stated that the effects of aging on the intended functions of the RPV and its components, including the vessel support skirt, shell, upper and lower heads, closure flanges and studs, nozzles and penetrations, nozzle safe ends, and refueling bellows support will be managed for the period of extended operation using the Metal Fatigue of Reactor Coolant Pressure Boundary Program for those locations with a CUF ratio predicted to exceed 0.4 in the original design-basis fatigue analysis or those locations identified in NUREG/CR-6260 for the newer-vintage General Electric plant. The applicant further stated that this aging management program (AMP) will monitor RPV and its components CUFs using either stress-based fatigue (SBF) monitoring or cycle-based fatigue (CBF) monitoring. LRA Table 4.3.1-2 summarizes RPV locations and its corresponding monitoring methods used to monitor the effects of aging using the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

LRA Section 4.3.1 states that SBF monitoring consists of computing a "real time" stress history for a given component from actual temperature, pressure, and flow histories via a finite element-based Green's Function approach. The applicant stated that CUF is then computed from the computed stress history using appropriate cycle counting techniques and appropriate ASME Code Section III fatigue analysis methodology. Furthermore, the NRC concern regarding the simplified input to the Greens' function of only one value of stress expressed in RIS 2008-30 has been addressed in completion of the work done for the applicant by completing a detailed stress analysis using the six stress components as discussed in ASME Code Section III, Subsection NB, Subarticle NB-3200. The applicant further stated that SBF monitoring is intended to duplicate the methodology used in the governing ASME Code stress report for the component in question, but uses actual transient severity in place of design-basis transient severity. The applicant stated that the confirmatory evaluation has been performed to verify the conservatism of the HCGS' use of Green's Function and associated SBF methodology. The staff noted that the LRA does not provide sufficient information or detail describing the confirmatory evaluation that was performed to verify the conservatism of the Green's Function and associated SBF methodology. The staff also noted that the LRA does not describe in detail how the FatiguePro® software will be used in monitoring the CUF for the RPV components and how the software will adjust if new transients are observed or the distributions of transients changes. During a teleconference call between the staff and the applicant on September 15, 2010, the applicant proposed that it will amend the LRA to state that the SBF monitoring module of FatiguePro® will not be used. The applicant also proposed that if SBF monitoring is used in the future, it will consider the six-stress terms in accordance with the methodology from ASME Code Section III, Subsection NB, Subarticle NB-3200. By letter dated September 20, 2010, the applicant amended LRA Section 4.3.1 to remove all references to the use of SBF monitoring. LRA Section 4.3.1, as amended by letter dated September 20, 2010, states that all of the CUF values reported for the RPV components in LRA Tables 4.3.1-2 and 4.3.5-1 were computed based on the fatigue tables from the design-basis calculations which consider the six stress terms in accordance with the methodology from ASME Code Section III, Subsection NB, Subarticle NB-3200. The applicant stated that the design-basis calculations were done using the code of record or updated to a later code edition pursuant to 10 CFR 50.55a, and therefore, the concerns of RIS 2008-30 have been addressed.

Based on its review, the staff finds the applicant's amendment to LRA Section 4.3.1 acceptable because the applicant: (1) does not rely on SBF monitoring software that uses a simplified input to the Greens' function of only one value of stress that was expressed in RIS 2008-30; (2) relies only on CBF monitoring that uses the design-basis fatigue calculations which consider the six stress terms in accordance with the methodology from ASME Code Section III, Subsection NB-3200 for the RPV components; and (3) addressed the concerns associated with RIS 2008-30.

LRA Section B.3.1.1 states that as a result of the high-pressure coolant injection (HPCI) event experienced in October 2004, the number of injection cycles exceeded the assumed number of cycles in the core spray nozzle fatigue analysis. The corrective action program was used to evaluate this event, resulting in an analysis indicating that the core spray nozzle CUF was 0.815. LRA Section 4.3.1 states that the applicant performed reanalysis for the core spray nozzle in accordance with ASME B&PV Code Section III, 2001 Edition including 2003 Addenda. This reanalysis resulted in the core spray nozzle 40-year CUF of 0.063. It is not clear to the staff what assumptions used in the core spray nozzle reanalysis resulted in reduction of CUF by a factor of 13. Further, the staff identified inconsistencies in core spray nozzle 60-year CUF values reported in LRA Tables 4.3.1-2 and 4.3.5-1.

By letter dated June 25, 2010, the staff issued RAI 4.3-03 requesting that the applicant clarify: (1) the assumptions used in the core spray nozzle reanalysis that resulted in a reduction of the CUF by a factor of 13 and (2) the inconsistencies in core spray nozzle 60-year CUF values reported in LRA Tables 4.3.1-2 and 4.3.5-1.

In its response dated July 22, 2010, the applicant stated that the CUF values for the core spray nozzle (safe end/thermal sleeve and nozzle body) in LRA Table 4.3.1-2 were inadvertently not updated to reflect the final results of the calculation revision completed during preparation of the LRA. The applicant further stated that the updated 60-year CUF values are 0.0202 and 0.1063 for the core spray nozzle (safe end/thermal sleeve) and the core spray nozzle (nozzle body), respectively. The applicant stated the design-basis 60-year CUF values presented in LRA Table 4.3.5-1 for the core spray nozzle (safe end/thermal sleeve and nozzle body) are based on the final results of the revised calculation, which is the current design analysis of record. The applicant noted that the values presented in LRA Table 4.3.1-2 should be consistent with those presented in LRA Table 4.3.5-1 and, therefore, LRA Table 4.3.1-2 was amended in the RAI response.

The applicant also stated in its response that prior to the most recent calculations performed for 60 years of operation for the core spray nozzle (safe end/thermal sleeve) in support of the LRA, the previous analysis performed to evaluate the October 2004 HPCI injection used the original core spray nozzle safe end design. The applicant stated that the original safe end design used a threaded-in thermal sleeve, and the analysis applied a stress concentration factor of 5 at this location which resulted in the primary plus secondary stress intensity range significantly exceeding 3 S_m (three times the design stress intensity) and a resulting K_e (simplified elastic-plastic strain correction factor) value of 3.33. The applicant stated that this threaded location became the bounding location which was evaluated in subsequent analyses, and the original analysis design-basis CUF value at the bounding location for 40 years was 0.796.

The applicant clarified that the safe end was replaced prior to initial plant operation but this configuration change was not incorporated into the previous fatigue analyses. The applicant stated the new configuration was an integral safe end without threads which was included in the revised finite element model and used to perform the fatigue analysis to support the LRA. The applicant also stated that the fatigue analysis performed for the LRA considered the integral safe end as fabricated of Alloy 600 instead of stainless steel, with a stainless steel thermal sleeve welded to the integral safe end, plus the addition of a new weld at the safe end to nozzle location. The applicant noted that beyond the changes in safe end design and material, the fatigue analysis performed for the LRA also refined the transient parameters, as compared to the simplified transient parameters used in the original analysis. The applicant further noted that these refinements included more detail with respect to time steps, nozzle and vessel temperatures and flows, and the use of actual lower flow rates associated with HPCI events when compared to flow rates shown in the thermal cycle diagram. The applicant stated that the thermal cycle diagram assumed all HPCI flow was injected through the core spray nozzle, even though the system is designed to split the flow between the core spray and feedwater nozzles. The applicant also stated that the fatigue summary from the previous fatigue analyses shows that the alternating stress values for all transient load set pairs were multiplied by the K, multiplier of 3.33, whereas only a few load set pairs in the current fatigue analysis are affected by K_e.

The staff finds the reduction in CUF from the original fatigue analyses compared to the fatigue analyses performed for the LRA reasonable because the combination of the safe end design and material change, refinements with respect to time steps, nozzle and vessel temperatures and flows, and the use of actual lower flow rates associated with HPCI events and the application of K_e to the affected load set pairs would result in removal of conservatism that was assumed in the original analysis. The staff noted that with regard to the nozzle body location, the original design-basis 40-year CUF was 0.071 and it did not experience as large of a reduction in calculated fatigue usage.

Based on its review, the staff finds the applicant’s response to RAI 4.3-03 acceptable because: (1) the applicant’s reduction in CUF for the core spray nozzle (safe end/thermal sleeve) was reasonable based on the collective differences between design (geometry and material) and the refinement of transient parameters, and (2) the applicant clarified the discrepancy between LRA Tables 4.3.1-2 and 4.3.5-1 and appropriately amended LRA Table 4.3.1-2 using the final calculation results. The staff's concern described in RAI 4.3-03 is resolved.

4.3.1.3 UFSAR Supplement

LRA Section A.4.3.1 provides the UFSAR supplement for the RPV fatigue analyses TLAA evaluation. Based on its review of the UFSAR supplement, the staff concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d) and consistent with SRP-LR Section 4.3.3.3.

4.3.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the RPV intended functions will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and therefore, is acceptable.

4.3.2 Reactor Pressure Vessel Internals Fatigue Analyses

4.3.2.1 Summary of Technical Information in the Application

LRA Section 4.3.2 summarizes the evaluation of the RPV internals fatigue analyses for the period of extended operation. This TLAA is based on the analysis in UFSAR Section 3.9.5.3.5. In this TLAA, the applicant stated that the HCGS RPV internals were designed to plant-specific design requirements and not designed to ASME B&PV Code requirements for core support structures, however, the components were identified as a TLAA. To project the RPV internals CUFs to 60 years, the applicant multiplied the 40-year CUF, as reported in UFSAR Table 3.9-4c, by a factor of 1.5. The applicant noted that a factor of 1.5 represents an increase in the plant life from 40 to 60 years. The applicant further stated that the primary contributor to fatigue of RPV internals is from non-thermal dynamic loads such as those derived from accidents or seismic events. In this TLAA, the applicant accepts the TLAA for RPV internals fatigue analysis based on the criterion in 10 CFR 54.21(c)(1)(ii), which permits the TLAA to be accepted if it can be demonstrated that the analysis has been projected to the expiration of the period of extended operation.

4.3.2.2 Staff Evaluation

The staff reviewed the TLAAs in LRA Section 4.3.2 for RPV internals fatigue analyses against the criteria in SRP-LR Section 4.3.2.1.1.2 and the review procedures in SRP-LR Section 4.3.3.1.1.2 in order to verify the analyses are in accordance with 10 CFR 54.21(c)(1)(ii) and that the analyses for the RPV internals have been projected to the end of the period of extended operation.

The staff also reviewed the following additional documents that are relevant to the staff's evaluation of this TLAA:

- TS 5.7, "Component Cyclic or Transient Limit"
- UFSAR Section 3.9.1.1.4, "Core Support Structures and Reactor Internals Transients"
- UFSAR Section 3.9.5.3.5, "Stress, Deformation, and Fatigue Limits for Engineered Safety Feature Reactor Internals (Except Core Support Structure)"
- UFSAR Table 3.9-1, "Plant Events"
- UFSAR Table 3.9-1a, "Plant Events – Feedwater Nozzles"
- UFSAR Table 3.9-4c, "Reactor Internals and Associated Equipment"
- 10 CFR 50.55a, "Codes and Standards"

The staff reviewed UFSAR Section 3.9.1.1.4, which states that the transients and the number of cycles specified in UFSAR Table 3.9-1 were used in 40-year fatigue analyses of the RPV internals. LRA Section 4.3.2 states that the applicant derived 60-year CUF values for RPV components by multiplying 40-year CUF values by a factor of 1.5, which represent an increase in the plant life from 40 to 60 years. The applicant stated that the RPV internals components in UFSAR Table 3.9-4c had CUFs of: (1) 0.111 for the core support plate (at stud), (2) 0.435 for the top guide (at beam slot), and (3) less than 0.05 for the core differential pressure sensing line (at elbow). The staff confirmed that by multiplying each of these CUF values by 1.5 would not lead to a CUF above the design limit. However, for some transients used in the RPV component fatigue analyses, the 40-year cycle projections summarized in LRA Table 4.3.1-1 exceed the values reported in UFSAR Table 3.9-1. Therefore, to project the RPV internals CUFs to 60 years, the fatigue analyses for these components need to be updated based on the 60-year cycle projections. However, LRA Section 4.3.2 does not provide sufficient information for the staff to determine whether 60-year RPV internals fatigue analyses have been updated to incorporate 60-year cycle projections.

By letter dated June 25, 2010, the staff issued RAI 4.3-04 requesting that the applicant clarify whether the fatigue analyses for RPV internals have been updated based on the 60-year cycle projections as summarized in LRA Table 4.3.1-1.

In its response dated July 22, 2010, the applicant stated that a review of the design-basis CUF calculations was performed for the core support plate (at stud), the top guide (at beam slot), and the core differential pressure sensing line (at elbow). The applicant has determined that the 60-year projections of the number of cycles for the transients which were paired within the scope of the design-basis CUF calculations for these components were determined to increase no greater than 1.5 times the 40-year design input pairing values in the original design-basis calculations. The applicant stated that, therefore, the use of the simple multiplication of the design-basis CUF by a factor of 1.5 is conservative relative to the CUF which would be calculated using the actual 60-year cycle projections for the transients that are within the scope of the CUF calculations for these components. The staff noted that the approach taken by the applicant is conservative because the use of 60-year cycle projections does not yield CUF values greater than multiplying the 40-year design-basis CUF by a factor of 1.5.

Based on its review, the staff finds the applicant's response to RAI 4.3-04 acceptable because the applicant's approach of multiplying the 40-year design-basis CUF by a factor of 1.5 is conservative and the CUF values for these components calculated using the 60-year cycle projections is not greater than those computed by the applicant's approach. The staff's concern described in RAI 4.3-04 is resolved.

4.3.2.3 UFSAR Supplement

LRA Section A.4.3.2 provides the UFSAR supplement of the RPV internals fatigue analyses TLAA evaluation. Based on its review of the UFSAR supplement, the staff concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d) and consistent with SRP-LR Section 4.3.3.3.

4.3.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the fatigue analyses of the RPV internals have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and therefore, is acceptable.

4.3.3 Reactor Coolant Pressure Boundary Piping and Component Fatigue Analyses

4.3.3.1 Summary of Technical Information in the Application

LRA Section 4.3.3 summarizes the evaluation of RCPB piping and component fatigue analyses for the period of extended operation. This TLAA is based on the analysis in UFSAR Section 3.2.2. In this TLAA, the applicant stated that the HCGS RCPB piping was designed in accordance with ASME B&PV Code Section III, Class 1 requirements and, therefore, was identified as a TLAA. The applicant further stated that high-energy line breaks (HELBs) in the HCGS piping have been postulated, and based on analyses performed on these breaks, means for avoiding damage to surrounding equipment and systems have been incorporated in the plant. The applicant performed 40-year design-basis fatigue analysis for HELB piping locations with allowable CUF values of 0.1 and, therefore, HELB locations are TLAAs. The applicant stated that the list of controlling transients is shown in LRA Table 4.3.1-1, which encompasses all transients listed in UFSAR Tables 3.9-1 and 3.9-1a. The applicant further stated that piping component locations with CUF ratios predicted to exceed 0.4 in the original design-basis fatigue analysis will be included in the Metal Fatigue of Reactor Coolant Pressure Boundary Program. In this TLAA, the applicant dispositioned the TLAA for RCPB piping and components based on the criterion in 10 CFR 54.21(c)(1)(iii), consistent with a demonstration that the effect of aging associated with the analysis will be adequately managed for the period of extended operation.

4.3.3.2 Staff Evaluation

The staff reviewed the TLAA in LRA Section 4.3.3 for RCPB piping and component fatigue analyses against the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 and the review procedures in SRP-LR Section 4.3.3.1.1.3 in order to verify the analyses are in accordance with 10 CFR 54.21(c)(1)(iii) and that the effects of aging on the RCPB piping intended functions will be adequately managed for the period of extended operation.

The staff also reviewed the following additional documents that are relevant to the staff's evaluation of this TLAA:

- TS 5.7, "Component Cyclic or Transient Limit"
- UFSAR Section 3.2.2, "System Quality Group Classification"
- UFSAR Section 3.9.1.1.5, "Main Steam System Transients"
- UFSAR Section 3.9.1.1.6, "Recirculation System Transients"
- UFSAR Table 3.9-1, "Plant Events"
- UFSAR Table 3.9-1a, "Plant Events – Feedwater Nozzles"
- 10 CFR 50.55a, "Codes and Standards"

The staff reviewed the applicant's cycle projection methodology in LRA Section 4.3.1, which is evaluated in SER Section 4.3.1.2. During its review, the staff confirmed that the transients used in the RCPB piping analyses have been included into the Metal Fatigue of Reactor Coolant Pressure Boundary Program, as summarized in LRA Table 4.3.1-1. The staff determined that the bounding piping components will be managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program using the CBF monitoring method. The staff determined that CBF monitoring performs cycle counting and CUF computations based on the counted cycles and, therefore, is acceptable for monitoring aging effects in RCPB piping. The staff further determined that the postulated allowable CUF value for HELB piping of 0.1 is based on the CLB and is below the code limit of 1.0. The staff noted that there were four components whose estimated 60-year CUF values exceeded the design limit of 0.1. These were the: (1) feedwater line node 197 with a CUF value of 0.136, (2) main steam line D with a CUF value of 0.124, (3) residual heat removal (RHR) shutdown cooling (SDC) return A node 601 with a CUF value of 0.113, and (4) RHR SDC return A node 608 with a CUF value of 0.106. The applicant indicated that these components would be managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program to ensure that appropriate actions will be taken prior to the allowable limit being exceeded by monitoring the numbers of cycles of the design transients, and the corresponding CUF for critical reactor coolant pressure boundary piping and components. The staff concluded that effects of aging in RCPB piping will be managed for the period of extended operation.

4.3.3.3 UFSAR Supplement

LRA Section A.4.3.3 provides the UFSAR supplement of the RCPB piping and component fatigue analyses TLAA evaluation. Based on its review of the UFSAR supplement, the staff concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d) and consistent with SRP-LR Section 4.3.3.3.

4.3.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the RCPB piping and component intended functions will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and therefore, is acceptable.

4.3.4 Non-Class 1 Component Fatigue Analyses

4.3.4.1 Summary of Technical Information in the Application

LRA Section 4.3.4 summarizes the evaluation of fatigue analyses for non-Class 1 component for the period of extended operation. This TLAA is based on the analysis in UFSAR Section 3.2. In this TLAA, the applicant stated that non-Class 1 components were designed in accordance with ASME B&PV Code Section III, Class 2 and 3 or American National Standards Institute (ANSI) B31.1/B31.7 piping code; therefore, fatigue analyses were not required, but cyclic loading was considered in a simplified manner for the design process.

The applicant analyzed stresses due to thermal expansion and anchor movement for non-Class 1 components identified in UFSAR Tables 3.2-1, 3.2-2, and 3.2-3, which include piping, tubing, fittings, tanks, vessels, heat exchangers, valve bodies, pump casting, and miscellaneous process components. The applicant indicated that the assumed thermal cycle count could be approximated by the thermal cycles expected for the RPV. The applicant combined all the expected transients in Table 4.3.1-1 and determined it was less than 2700 for 60 years of plant operation. Because this is less than the acceptance criteria of 7,000, the applicant determined that piping analyses designed to ANSI B31.1 or ASME Code Section III, Class 2 and 3 are valid within the scope of license renewal. The applicant dispositioned the TLAA for non-Class 1 component fatigue analyses based on the criterion in 10 CFR 54.21(c)(1)(i), consistent with a demonstration that the current analysis remains valid for the period of extended operation.

4.3.4.2 Staff Evaluation

The staff reviewed the TLAA in LRA Section 4.3.4 for non-Class 1 component fatigue analyses against the acceptance criteria in SRP-LR Section 4.3.2.1.2.1 and the review procedures in SRP-LR Section 4.3.3.1.2.1 in order to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

The staff also reviewed the following additional documents that are relevant to the staff's evaluation of this TLAA:

- TS 5.7, “Component Cyclic or Transient Limit”
- UFSAR Section 3.2.2, “System Quality Group Classification”
- UFSAR Table 3.2-1, “HCGS Classification of Structures, Systems, and Components”
- UFSAR Table 3.2-2, “Code Group Designation – Industry Codes and Standards for Mechanical Components (NSSS Scope)”
- UFSAR Table 3.2-3, “Code Requirements for Components and Quality Groups for Public Service Electric and Gas Company/Bechtel-Procured Components”
- UFSAR Table 3.9-1, “Plant Events”

- UFSAR Table 3.9-1a, “Plant Events – Feedwater Nozzles”
- 10 CFR 50.55a, “Codes and Standards”

The staff reviewed the applicant’s cycle projection methodology in LRA Section 4.3.1, which is evaluated in SER Section 4.3.1.2. During its review, the staff determined that the applicant assumed a thermal cycle counts for non-Class 1 components that are the same as the thermal cycles expected for the RPV and its components. The applicant used 60-year projections derived for these events as summarized in LRA Table 4.3.1-1. The applicant determined that 60-year projected number of thermal cycles applicable to non-Class 1 components is less than 2700 and, therefore, would not exceed the cycle threshold of 7000 cycles.

The staff issued RAI 4.3-02 due to concerns about the applicant’s cycle projection methodology. RAI 4.3-02 and the applicant’s response to RAI 4.3-02 is evaluated in SER Section 4.3.1.2. The staff’s concern described in RAI 4.3-02 is resolved and the projected number of cycles for this TLAA is acceptable.

Based on its review, the staff finds that the fatigue evaluation for the non-Class 1 components remains valid for the period of extended operation since the allowable number of cycles, at maximum displacements for normal operating conditions, is greater than those projected for 60 years.

4.3.4.3 UFSAR Supplement

LRA Section A.4.3.4 provides the UFSAR supplement of the non-Class 1 component fatigue analyses TLAA evaluation. Based on its review of the UFSAR supplement, the staff concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d) and consistent with SRP-LR Section 4.3.3.3.

4.3.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for non-Class 1 components remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and therefore, is acceptable.

4.3.5 Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping (Generic Safety Issue 190)

4.3.5.1 Summary of Technical Information in the Application

LRA Section 4.3.5 summarizes the evaluation of the environmentally-assisted fatigue (EAF) analyses for the period of extended operation. This TLAA is based on the analysis in NUREG/CR-6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components.”

In this TLAA, the applicant stated that the effects of the reactor coolant system environment on fatigue life were evaluated for the following representative components that are identified in NUREG/CR-6260 for newer vintage General Electric plants:

- RPV shell and lower head
- RPV feedwater nozzle
- reactor recirculation piping (including RPV inlet and outlet nozzles)
- core spray line RPV nozzle and associated Class 1 piping
- RHR nozzles and associated Class 1 piping
- feedwater Class 1 piping

The applicant stated that the plant-specific limiting locations were identified for the NUREG/CR-6260 sample locations and EAF calculations were performed following the guidance of NUREG/CR-6583, “Effects of LWR Coolant Environments on Fatigue Curves of Carbon and Low-Alloy Steels,” for components made of carbon and low-alloy steels and the guidance of NUREG/CR-5704, “Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels,” for components made of austenitic stainless steel. The applicant further stated that EAF results showed that CUFs which include environmental effects would not exceed the code limit of 1.0 for 60 years of plant operation for all locations except the RPV feedwater nozzle safe end, which had a projected CUF of 2.3810. However, the applicant included all plant-specific limiting locations identified for the NUREG/CR-6260 sample locations into the Metal Fatigue of Reactor Coolant Pressure Boundary Program, which provides for corrective actions to prevent the CUF from exceeding the design code limit. The applicant dispositioned the TLAA for EAF analyses based on the criterion in 10 CFR 54.21(c)(1)(iii), based on a demonstration that the effects of aging associated with the analysis will be adequately managed for the period of extended operation.

4.3.5.2 Staff Evaluation

The staff reviewed the TLAA in LRA Section 4.3.5 for EAF analyses against the acceptance criteria in SRP-LR 4.3.2.2 and the review procedures in SRP-LR Section 4.3.3.2 in order to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The staff also reviewed the following additional documents that are relevant to the staff’s evaluation of this TLAA:

- NUREG/CR-6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components”

- NUREG/CR-6583, “Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels”

- NUREG/CR-5704, “Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steel”

During its review, the staff noted that the applicant identified the plant-specific components and limiting component locations for the NUREG/CR-6260 sample locations and performed EAF calculations for these components to evaluate the effects of the reactor coolant system environment on fatigue life. The applicant indicated that it chose the locations based on the required evaluations from NUREG/CR-6260. The staff noted that there were other reactor components with high 60-year projected CUF values, such as the feedwater piping line on LRA Table 4.3.3-1 with a 0.841 CUF that was not evaluated for environmental effects. The staff determined that LRA Section 4.3.5 does not provide sufficient information on the methodology used in determining the plant-specific components and limiting component locations for the NUREG/CR-6260 sample locations.

By letter dated June 25, 2010, the staff issued RAI 4.3-05 requesting that the applicant explain the methodology used in determining the plant-specific components and limiting component locations for the NUREG/CR-6260 sample locations.

In its response dated July 22, 2010, the applicant clarified its basis for the components analyzed for EAF shown in LRA Table 4.3.5-1. The applicant provided a table that clarified its basis for selecting the RCPB locations that were considered to be the equivalent bounding HCGS sample locations recommended in NUREG/CR-6260, as applied to new-vintage General Electric designed BWRs. The applicant also clarified its basis for concluding that these components were the most limiting. The applicant clarified that a review of its design basis did not identify any additional locations more limiting than those analyzed for EAF in LRA Table 4.3.5-1.

The staff reviewed the applicant's component locations analyzed for EAF in LRA Table 4.3.5-1. The staff compared this information to applicable design-basis CUF data and 60-year projected CUF data that the applicant provided for RV components in LRA Table 4.3.1-2 and for ASME Code Class 1 piping locations in LRA Table 4.3.3-1. The staff confirmed that, with the exception of the Class 1 portion of the feedwater piping, the applicant selected at least two component locations as being representative of each component location that was recommended in NUREG-6260. The information in the fourth column of SER Table 4.3.5-1 shown below provides the staff's basis for accepting that the applicant's selections of the component locations for EAF analysis are valid and conservative:

Table 4.3.5-1 Basis for Accepting Applicant EAF Analysis Locations

NUREG/CR-6260 Recommended Location	HCGS EAF Location	HCGS Basis for Picking Equivalent Location	The Staff's Basis for Accepting the Applicant's EAF Component Location
RV Shell and Lower Head	Control Rod Drive (CRD) Housing Weld	The applicant identified this component as an additional RV shell or lower head component for EAF analysis. The applicant stated that this component is the most limiting RV shell and lower head component for EAF and that the housings are made from stainless steel and the CRD housing-to-nozzle welds are made from stainless steel material.	The staff confirmed that even though the CRD housing is welded to CRD penetration nozzles, the housings are more appropriately considered as CRD piping locations. The staff also confirmed that LRA Table 4.3.5-1 identifies that the 60-year EAF for CRD housing welds are more limiting than the CRD penetration nozzles. The staff noted that the housing welds are more limiting for EAF because they are subjected to a much higher F_{en} adjustment factor. The staff finds the inclusion of the CRD housing welds as the limiting RV shell and lower head component for EAF to be valid and conservative because it is more limiting than the CRD penetration nozzle location. This demonstrates the validity of the applicant's response to RAI 4.3-05, Request 2 that additional components do not need to be analyzed for EAF beyond those assessed in

NUREG/CR-6260 Recommended Location	HCGS EAF Location	HCGS Basis for Picking Equivalent Location	The Staff's Basis for Accepting the Applicant's EAF Component Location
			LRA Table 4.3.5-1.
	CRD Penetrations with Excavation	Additional RV shell component even though the CRD housing welds are considered to be more limiting. The penetration nozzle is fabricated from Alloy 600.	The staff confirmed that the component type is welded to the RV lower head and is considered to be an RV appurtenance. The staff finds the inclusion of this component for EAF analysis to be a conservative practice because the component is equivalent to the NUREG/CR-6260 RV shell and lower head location.
RV Feedwater Nozzle	Feedwater Nozzle	Applied NUREG-recommended component for EAF calculations.	The staff finds the inclusion of this component for EAF analysis valid and conservative because the component is equivalent to the NUREG/CR-6260 feedwater nozzle location.
	Feedwater Nozzle Safe End	Safe end was conservatively included as an additional feedwater nozzle component location because this feedwater nozzle component was more limiting for EAF than the feedwater nozzle itself.	The staff confirmed that LRA Table 3.1.2-1 lists the feedwater nozzle safe end as an RV component and that the applicant identified this as an additional feedwater nozzle equivalent location for EAF analysis. The staff finds the inclusion of the feedwater nozzle safe end for EAF analysis to be valid and conservative because the component represents an additional equivalent feedwater nozzle location and the EAF value for the feedwater nozzle safe end is more limiting than that listed in LRA Table 4.3.5-1 for the feedwater nozzle. The staff noted that this demonstrates the validity of the applicant' response to RAI 4.3-05, Request 2 that there does not need to be an additional feedwater nozzle component location analyzed for EAF beyond those in LRA Table 4.3.5-1.
Reactor Recirculation Piping (including RV inlet and outlet nozzles)	RHR Return Tee	Provided as the equivalent Class 1 reactor recirculation piping location.	The staff confirmed that the applicant listed the Class 1 RHR return tee in the reactor recirculation loop in LRA Table 4.3.5-1 because it represents the equivalent Class 1 reactor recirculation piping location and the return tee represented the most limiting reactor recirculation piping component for EAF due to its high F_{en} factor.
	RV Inlet Nozzle Forging	Provided as the equivalent RV inlet nozzle location.	The staff confirmed that the applicant appropriately listed RV inlet nozzle forging for EAF in LRA Table 4.3.5-1 because it represents the equivalent RV inlet nozzle location.
	RV Outlet Nozzle Forging	Provided as the equivalent RV outlet nozzle location.	The staff confirmed that the applicant appropriately listed RV outlet nozzle forging for EAF in LRA Table 4.3.5-1 because it represents the equivalent RV outlet nozzle location.
Core Spray Line RV Nozzle and Associated Class 1 Piping	Core Spray Nozzle	Provided as the equivalent core spray nozzle location.	The staff confirmed that the applicant appropriately listed RV inlet nozzle forging for EAF in LRA Table 4.3.5-1 because it represents the equivalent core spray nozzle location.

NUREG/CR-6260 Recommended Location	HCGS EAF Location	HCGS Basis for Picking Equivalent Location	The Staff's Basis for Accepting the Applicant's EAF Component Location
	Core Spray Nozzle Safe End	Provided as the equivalent core spray line piping location.	The staff noted that, although LRA Table 3.1.2-1 lists the core spray nozzle safe end as an RV component, the component represents an additional spool of pipe that is welded to the core spray nozzle on one end and to the core spray piping on its opposite end. The staff finds that the applicant identified the core spray safe end locations as the equivalent core spray piping location. The staff also confirmed that the core spray nozzles are the more limiting core spray line component for EAF. Therefore, the staff finds that the inclusion of the core spray nozzle safe end for EAF analysis is conservative and acceptable.
RHR Class 1 Piping	RHR Supply Piping from Stainless Steel	Provided as the equivalent Class 1 RHR piping location for piping made from stainless steel.	The staff confirmed that the applicant appropriately listed this RHR piping for EAF in LRA Table 4.3.5-1 because it represents an equivalent Class 1 RHR piping location and the applicant conservatively listed both an equivalent stainless steel RHR piping location and a carbon steel RHR piping location for EAF in LRA Table 4.3.5-1. This component represents the stainless steel entry.
	RHR Supply Piping from Carbon Steel	Provided as the equivalent Class 1 RHR piping location for piping made from carbon steel.	The staff confirmed that the applicant appropriately listed this RHR piping for EAF in LRA Table 4.3.5-1 because it represents an equivalent Class 1 RHR piping location and the applicant conservatively listed both an equivalent stainless steel RHR piping location and a carbon steel RHR piping location for EAF in LRA Table 4.3.5-1. This component represents the carbon steel entry.
Class 1 Feedwater Piping	Tee on Header to RV Feedwater Nozzle N4E	Provided as the equivalent Class 1 feedwater piping location.	The staff confirmed that the applicant appropriately listed feedwater tee for EAF in LRA Table 4.3.5-1 because it represents the equivalent Class 1 feedwater piping location.

The staff noted that the Feedwater Line No. AE-036, node 200 has a 60-year CUF of 0.841. However the RPV feedwater nozzle (safe end and nozzle forging) and feedwater Class 1 piping (tee on header to RPV Nozzle N4E) which were evaluated for reactor water environmental effects, consistent with NUREG/CR-6260, have lower 60-year CUF values. The staff is unclear whether the Feedwater Line No. AE-036, node 200 should be evaluated for reactor water environmental effects or if it is bounded by the locations that have already been evaluated for reactor water environmental effects. In addition, the staff needs confirmation that the applicant has verified that estimated 60-year CUF values for LRA Table 4.3.3-1 are still conservative and bounded, as compared to those of components in LRA Table 4.3.5-1, when adjusted for environmental effects. This is identified as confirmatory item CI 4.3.5.2-1.

By letter dated January 6, 2011, the applicant responded to confirmatory item CI 4.3.5.2-1. The applicant's response was separated into the following three subject areas:

A. The review of the selection of the limiting NUREG/CR-6260 feedwater Class 1 piping location.

B. The review of the CUF values presented in LRA Tables 4.3.3-1 and 4.3.5-1.

C. A commitment to perform additional reviews to confirm the limiting HCGS locations per NUREG/CR-6260 are bounding as compared to other plant-specific locations.

In response to subject area A, the applicant stated that it performed a verification to confirm the limiting locations evaluated per NUREG/CR-6260 are bounding as compared to other plant-specific locations (e.g. Feedwater line No. AE-036, node 200/130) for the feedwater Class 1 piping. The applicant described the actions taken for this verification, which included a review of the feedwater piping values of LRA Table 4.3.3-1 and the basis documents which support the table.

From this review, the applicant concluded that Feedwater Line No. AE-035 Node 200 instead of Feedwater Line No. AE-036 Node 130 listed in LRA Table 4.3.3-1 should have been used to determine the EAF CUF for feedwater piping in LRA Table 4.3.5-1. The staff noted that the applicant's conclusion was based on using the highest design-basis 40-year CUF. The applicant indicated that the use of Node 130 instead of Node 200 was caused by an error in the stress report input during the preparation of the calculations for the LRA. The applicant clarified that Node 200 is at the terminal end of the piping system where it attaches to the RPV feedwater nozzle safe end.

The staff noted that based on these results, the applicant reviewed the feedwater nozzle analysis since it includes the bounding terminal end of the piping. The staff noted that the feedwater nozzle analysis results shown in LRA Table 4.3.5-1 were obtained from an ASME Section III NB-3200 analysis that used a finite element model that included the low alloy steel nozzle forging, the carbon steel safe end (with a stainless steel inlay), and the terminal end of the carbon steel pipe that correlates with AE-035 Node 200.

The applicant stated that this NB-3200 analysis of the feedwater nozzle was performed using loads that are bounding for all the feedwater nozzles and the finite element model showed that the highest stress location within the nozzle assembly was in the safe end. The staff finds that since the safe end was shown to be the highest stress location, which results in the highest fatigue usage, it can be considered bounding for the terminal end of the carbon steel pipe, which correlates to AE-035 Node 200. The applicant stated that the 60-year CUF value for the safe end is 0.1982 and that by applying the carbon steel F_{en} multiplier of 4.73 for the feedwater piping, an environmentally-adjusted CUF value of 0.9375 is determined for AE-035 Node 200. The staff's review of the applicant's assumptions used to determine the carbon steel F_{en} multiplier of 4.73 is discussed in RAI 4.3-06 and documented in SER Section 4.3.5.2.

The applicant also clarified the higher 60-year projected CUF value of 0.841, in LRA Table 4.3.3-1, for Feedwater Line No. AE-036 Node 200 as compared to other feedwater piping locations. The staff noted that the design-basis CUF calculations, for both Feedwater Line No. AE-035 Node 200 and AE-036 Node 200, include the operating basis earthquake (OBE) transient, and the estimated 40-year and 60-year CUF calculations were based on projected transients. The staff noted that the estimated 40-year and 60-year CUF calculations did not assume an OBE transient, consistent with LRA Table 4.3.1-1, because the numbers of occurrences expected for 40 and 60 years of operation were obtained by extrapolating the numbers of occurrences actually incurred to-date. The staff's review of the applicant's projection methodology is discussed in RAI 4.3-02 and documented in SER Section 4.3.1.2. The staff finds it acceptable that the applicant did not consider the OBE transient in the estimated 40-year and 60-year CUF calculations because: (1) the projected cycles for 40 and 60 years of operation and the estimated 40-year and 60-year CUF calculations were provided in the LRA as information only and does not represent the applicant's design calculations or analysis of record and (2) the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program will continue to monitor and track those transients that are important to determining a CUF, during the period of extended operation.

The applicant stated that the OBE transient has a higher impact on Feedwater Line No. AE-035 Node 200 analysis than it does on the Feedwater Line No. AE-036 Node 200 analysis. The staff finds it reasonable that the estimated 60-year projected CUF was higher for Feedwater Line No. AE-036 Node 200, although the design CUF for Feedwater Line No. AE-035 Node 200 was greater than Feedwater Line No. AE-036 Node 200, because the OBE transient has a higher impact on Feedwater Line No. AE-035 Node 200 and was not included in the estimated 60-year projected CUF.

The staff noted that the applicant amended LRA Table 4.3.5-1 to indicate that the terminal end of piping at the feedwater nozzle safe end at the applicant's site corresponds to the NUREG/CR-6260 location, "Feedwater Class 1 Piping."

Based on its review, the staff finds the applicant's response to CI 4.3.5.2-1, subject area A, acceptable because: (1) the applicant considered the effects of reactor water environment on fatigue life on the most bounding location, Feedwater Line No. AE-035 Node 200, for the feedwater Class 1 piping; (2) the environmentally adjusted CUF for this location was below the design limit of 1.0; (3) the applicant justified the difference in the estimated 60-year CUF between Feedwater Line No. AE-036 Node 200 and AE-035 Node 200, as described above; and (4) the applicant will continue to monitor fatigue usage, including environmental effects, for this location with its Metal Fatigue of Reactor Coolant Pressure Boundary Program.

In response to subject area B, the applicant stated that as a result of the stress report input error identified for the feedwater Class 1 piping component location, a comprehensive review of the stress reports supporting the LRA tables was performed. During this review, the applicant found that the stress report for the reactor water cleanup (RWCU) piping system contained a second 40-year design CUF value at Node 905, which is higher than that reported in LRA Table 4.3.3-1. The applicant stated that RWCU Node 905 is located at the transition between carbon steel piping and stainless steel piping. Furthermore, the higher CUF value of 0.573 is attributed to the evaluation of stainless steel material at this location, which is in addition to the CUF value of 0.523 for carbon steel already presented in LRA Table 4.3.3-1. The applicant clarified that the weld material used at this transition is stainless steel. Based on its review, the applicant concluded that the remaining values in LRA Table 4.3.3-1 and LRA Table 4.3.5-1 are correct based on the stress report inputs.

The applicant stated that other than the feedwater Class 1 piping, its review also concluded the component locations in LRA Table 4.3.5-1 are the limiting plant-specific locations that correlate with the NUREG/CR-6260 components, however, additional plant-specific locations may exist which are more limiting than those considered in NUREG/CR-6260. The staff noted the applicant will perform an additional review as described in Commitment No. 54 and subject area C.

In response to subject area C, the applicant committed (Commitment No. 54) to the following:

> PSEG will perform a review of design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 based locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the Hope Creek plant configuration. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage. If any of the limiting locations consist of nickel alloy, NUREG/CR-6909 methodology for nickel alloy will be used in the evaluation.

The applicant stated that these additional evaluations will be performed through the Metal Fatigue of Reactor Coolant Pressure Boundary Program and the most limiting location will be monitored in accordance with 10 CFR 54.21(c)(1)(iii).

Based on its review, the staff finds the applicant's response to CI 4.3.5.2-1, subject area B, acceptable because: (1) as a result of the stress report input error identified for the feedwater Class 1 piping, the applicant took corrective actions to ensure that the remaining CUF values reported in the LRA are accurate and correct; (2) the applicant identified a second 40-year design CUF value at RWCU Node 905 that corresponded to the stainless steel material at this node and amended LRA Table 4.3.3-1, as appropriate; and (3) the applicant verified that the remaining values in LRA Table 4.3.3-1 and LRA Table 4.3.5-1 are correct based on stress report inputs.

Based on its review, the staff finds the applicant's response to CI 4.3.5.2-1, subject area C, and Commitment No. 54 acceptable because: (1) the applicant will review its design-basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 based locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for its plant configuration; (2) if a more limiting location is identified, the applicant will perform EAF analyses for the most limiting location; (3) the methodology consistent with NUREG/CR-6909 will conservatively be used in the evaluation, if the limiting component identified consists of nickel alloy; and (4) Commitment No. 54 is consistent with the recommendations in SRP-LR Sections 4.3.2.2 and 4.3.3.2, and GALL AMP X.M1, to consider environmental effects for the NUREG/CR-6260 locations, at a minimum. Confirmatory item CI 4.3.5.2-1 is closed.

The staff's review of LRA Section 4.3.5, identified that the applicant had used NUREG/CR-6583 and NUREG/CR-5704 to determine the environmental fatigue multiplier (F_{en}). However, the staff determined that the LRA does not provide sufficient information on the basis for assumptions used in calculating the F_{en} values for the NUREG/CR-6260 sample locations. By letter dated June 25, 2010, the staff issued RAI 4.3-06 requesting that the applicant provide the basis for assumptions used (e.g., sulfur content, dissolved oxygen, temperature, strain rate) in the F_{en} calculations for the NUREG/CR-6260 sample locations.

In its response dated July 22, 2010, the applicant clarified the assumptions used in the derivation of its F_{en} factors for the EAF calculations. For calculation of F_{en} factors for transients that are driven by dynamic loading, the applicant stated that it assumed a F_{en} value of 1.0. For these types of transients, the applicant stated that the dynamic loadings occur too rapidly for a contribution of the reactor coolant environment on the stress range for the transients.

The staff noted that acceptable recommendations for calculating F_{en} factors are provided in NUREG/CR-6583 for carbon steel or low-alloy steel materials and in NUREG/CR-5704 for austenitic stainless steel materials. The staff also noted that the NRC recommendations for calculating F_{en} factors apply to those transients that are thermally driven and in which the exposure of the reactor coolant environment could impact the material properties associated with a component's material of fabrication and potentially the growth rate for any microcracks that are postulated in the component's material. The staff noted that the applicability of the staff's EAF recommendations and application of F_{en} factor apply only to those transients in which there is ample time for the reactor coolant to impact the component. Therefore, the staff finds the applicant's application of a F_{en} factor of 1.0 for dynamic load transients to be a reasonable assumption because the contribution of the reactor coolant on the stress ranges for dynamic load transients is negligible.

For the remaining transients, the applicant clarified that the following strain rate and temperature assumptions were used to derive the F_{en} factors:

- For all cases, the strain rates and sulfur content used in derivation of the F_{en} factors were those that maximized the F_{en} values.

- For all cases, the temperatures used in derivation of the F_{en} factors assumed a design temperature of 550 °F; for the feedwater nozzles, the derivation of the F_{en} factor used the maximum temperature for each load pair in the CUF calculation for the component.

The staff noted that the applicant's use of the design temperature of the component is reasonable because this should be the maximum temperature the component would experience during any transient. The staff finds the use of these assumptions to be acceptable because: (1) the F_{en} factors would be maximized based on the slow strain rate and high sulfur content; (2) the applicant used the design temperature of the component; and (3) for the feedwater nozzle, the applicant used a refined approach.

The applicant clarified that the dissolved oxygen level used for the derivation of the F_{en} factors applied a weighted average of the dissolved oxygen content concentration in the reactor coolant for both the period when normal water chemistry (NWC) control was applied and the period when hydrogen water chemistry (HWC) was applied at the facility. The staff noted the weighted average for NWC accounts for 15 percent of the time at power operations and HWC accounts for 85 percent of the time at power operations, including time during the period of extended operation. The applicant clarified that the average of the dissolved oxygen content value for NWC conditions and HWC conditions used the measured oxygen content values, as taken and measured in accordance with its chemistry sampling and testing processing activities for the primary coolant.

Based on its review, the staff finds the applicant's response to RAI 4.3-06 acceptable because the applicant: (1) applied those strain rates and sulfur content values that maximized the contributions to the F_{en} factors; (2) either applied appropriate design-basis temperature or transient temperatures to the F_{en} factor; and (3) appropriately accounted for dissolved oxygen conditions for both NWC and HWC, as derived from actual plant records or conservatively estimated based on those from documented records for periods when NWC and HWC were in effect. The staff's concern described in RAI 4.3-06 is resolved.

During the staff's review of LRA Section 4.3.5, the applicant stated that the F_{en} factor of 1.49 was used for the Alloy 600 component (CRD penetration and core spray nozzle). However, the staff determined that the LRA does not provide sufficient information to determine what methodology was used in obtaining F_{en}.

By letter dated June 25, 2010, the staff issued RAI 4.3-07 requesting that the applicant: (1) justify using the value of 1.49 for the F_{en} factor if it is not a bounding/conservative value for the Alloy 600 component when compared to the F_{en} factor calculated based on NUREG/CR-6909 for nickel alloys, and (2) describe the current or future planned actions to update the CUF calculation with the F_{en} factor for the Alloy 600 component only, consistent with the methodology in NUREG/CR-6909.

In its response dated July 22, 2010, the applicant stated that a review was performed that indicates that using the NUREG-6909 methodology would result in a conservative value for a F_{en} of 3.56. The applicant stated that Equations A.14 through A.17 contained in Appendix A to NUREG/CR-6909 were used and the review was based on a reactor maximum temperature of 550 °F and a value for transformed strain rate to maximize F_{en}. Furthermore, an overall HWC availability of 85 percent was accounted for when computing the F_{en} of 3.56. The applicant stated that when using the NUREG/CR-6909 methodology, the resultant EAF CUF for the CRD penetration with excavation is 0.80 and for the core spray nozzle safe end, the resultant EAF CUF is 0.10. The staff noted that for both components, the resultant EAF CUF is below the ASME Code design limit of 1.0. The applicant further stated that a conservative application of the NUREG/CR-6909 methodology for the Alloy 600 locations (CRD penetration with excavation and core spray nozzle safe end) determined that the 60-year CUF values with a F_{en} factor remain below 1.0 and are acceptable for the period of extended operation, therefore, there are no planned actions to update the CUF calculations with a F_{en} factor consistent with the methodology in NUREG/CR-6909.

By letter dated September 9, 2010, the applicant amended its response to RAI 4.3-07 by stating that future revisions or updates to the environmental fatigue calculations for Alloy 600 locations will use the data and the methodology that is described in NUREG/CR-6909 or later revisions/reports for Ni-Cr-Fe alloys to determine the F_{en} factor and fatigue usage. The staff noted that LRA Table 4.3.1-2 states that the CRD penetration with excavation and core spray nozzle safe end components are monitored by CBF monitoring, in which CUF is determined by using the actual number of transients that occur and assumes each actual transient has a severity equal to that assumed in the design basis.

The staff finds it acceptable that the applicant will use the methodology in NUREG/CR-6909 in future revisions or updates to the environmental fatigue calculations because: (1) the applicant counts the number of transient cycles, determines the CUF assuming the severity is equal to that assumed in the design basis, and ensures the design limit of 1.0 is not exceeded, and (2) the 60-year CUF value with a F_{en} for both Alloy 600 components before and after using the worse-case F_{en} factor from NUREG/CR-6909 is below the design limit of 1.0.

Based on its review, the staff finds the applicant's response to RAI 4.3-07, as supplemented by letter dated September 9, 2010, acceptable because: (1) the applicant calculated the worse-case F_{en} factor for its Alloy 600 components consistent with NUREG/CR-6909, (2) the 60-year CUF value with a F_{en} for both Alloy 600 components before and after using the worse-case F_{en} factor calculated consistent with NUREG/CR-6909 is below the design limit of 1.0, (3) the effects of aging for these Alloy 600 components will be managed by the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program that will take corrective actions prior to the 60-year CUF value with a F_{en} exceeding the design limit of 1.0, and (4) the applicant committed (Commitment No. 53) to use the data and the methodology that is described in NUREG/CR-6909 or later revisions or reports for Ni-Cr-Fe alloys in the determination of the F_{en} factor and fatigue usage in its environmental fatigue calculations upon calculation revisions. The staff's concern described in RAI 4.3-07 is resolved.

4.3.5.3 UFSAR Supplement

LRA Section A.4.3.5 provides the UFSAR supplement for the effects of reactor coolant environment on fatigue life of components and piping (Generic Safety Issue-190) TLAA evaluation. Based on its review of the UFSAR supplement, the staff concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d) and consistent with SRP-LR Section 4.3.3.3.

4.3.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging associated with reactor coolant environment on fatigue for component piping intended functions will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and, therefore, is acceptable.

4.4 Environmental Qualification of Electrical Equipment

4.4.1 Summary of Technical Information in the Application

LRA Section 4.4 summarizes the evaluation of environmental qualification (EQ) of electrical equipment for the period of extended operation. The applicant stated that the HCGS EQ program is in compliance with the requirements of 10 CFR 50.49 and is being used to manage the aging of equipment in the EQ program during the current license term. The applicant also stated that the existing HCGS EQ program will be used to manage aging of equipment in the EQ program during the period of extended operation and includes provisions to ensure that the qualification bases are maintained and the components do not exceed their qualified lives. The applicant further stated TLAA disposition to 10 CFR 54.21(c)(1)(iii), which states that the effects of aging will be adequately managed for the period of extended operation, and the EQ of Electric Components Program will manage the aging effects of the components associated with the EQ TLAA.

4.4.2 Staff Evaluation

The EQ requirements established by 10 CFR Part 50, Appendix A, Criterion 4 and 10 CFR 50.49 specifically require each applicant to establish a program to qualify electrical equipment so that such equipment, in its end of life condition, will meet its performance specifications during and following design-basis accidents. The 10 CFR 50.49 EQ program is a TLAA for purposes of license renewal. The TLAA of the EQ of electrical components includes all long-lived, passive, and active electrical and instrumentation and controls (I&C) components that are important to safety and are located in a harsh environment. The harsh environments of the plant are those areas subject to environmental effects by a LOCA, HELB, or post-LOCA environment. EQ equipment is comprised of safety-related, nonsafety-related equipment that the failure of which could prevent satisfactory accomplishment of any safety-related function, and necessary post-accident monitoring equipment.

The staff reviewed LRA Sections 4.4 and B.3.1.2, plant basis documents, additional information provided to the staff, and interviewed staff personnel to verify whether the applicant provided adequate information to meet the requirement of 10 CFR 54.21(c)(1). For electrical equipment, the applicant uses 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate that the aging effects of EQ equipment will be adequately managed during the period of extended operation.

Per NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Revision 1, dated September 2005, plant EQ programs that implement the requirements of 10 CFR 50.49 are considered acceptable AMPs for meeting the requirements of 10 CFR 54.21(c)(1)(iii). GALL AMP X.E1, “Environmental Qualification (EQ) of Electric Components,” provides a means to meet the requirements of 10 CFR 54.21(c)(1)(iii).

The staff’s evaluation of the applicant’s EQ of Electric Components Program is documented in SER Section 3.0.3.1.22. The staff reviewed the applicant’s 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 for the period of extended operation.

The staff's evaluation of the component's qualification focused on how the EQ program manages the aging effects to meet the requirements pursuant to 10 CFR 50.49. The staff conducted an audit of the information provided in LRA Sections 4.4 and B.3.1.2 and program basis documents. LRA Section 4.4 discusses the component reanalysis attributes, including analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions.

On the basis of its audit, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL AMP X.E1. Based on its audit, the staff finds that elements one through six of the applicant's EQ of Electric Components Program are consistent with the corresponding program elements of GALL AMP X.E1 and, therefore, acceptable. The staff further concludes that the applicant's EQ of electric equipment TLAA is implemented per the requirements of 10 CFR 54.21(c)(1)(iii).

Therefore, the staff finds that the applicant's EQ program demonstrates, pursuant to 10 CFR 54.21(c)(1)(iii), that the effect of aging on the intended function(s) will be adequately managed for the period of extended operation. The applicant's EQ program is, therefore, capable of programmatically managing the qualified life of components within the scope of the program for license renewal. The continued implementation of the EQ program provides assurance that the aging effects will be managed and that components within the scope of the EQ program will continue to perform their intended functions for the period of extended operation.

4.4.3 UFSAR Supplement

LRA Section A.4.4 provides the UFSAR supplement for the EQ of electrical equipment TLAA evaluation. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 4.4-1 and 4.4-2. The staff concludes that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

4.4.4 Conclusion

On the basis of its review of the applicant's EQ of electrical equipment TLAA, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained pursuant to 10 CFR 54.21(c)(1)(iii) for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

4.5 Loss of Prestress in Concrete Containment Tendons

4.5.1 Summary of Technical Information in the Application

LRA Section 4.5, stated that HCGS containment does not have prestressed tendons. As such, loss of prestress in concrete containment tendons is not a TLAA.

4.5.2 Staff Evaluation

The staff reviewed the applicant's UFSAR supplement and confirmed that the containment does not have prestressed tendons and, therefore, finds the applicant's statement acceptable.

4.5.3 UFSAR Supplement

LRA Section A.4.5 provides the UFSAR supplement for the fatigue analyses of loss of prestress in concrete containment tendons TLAA evaluation. The staff reviewed the applicant's UFSAR supplement and confirmed that the containment does not have prestressed tendons and, therefore, finds the applicant's statement acceptable. The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d) and consistent with SRP-LR Section 4.5.3.2.

4.5.4 Conclusion

Based on its review, the staff concludes that loss of prestress in concrete containment tendons is not a TLAA. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and, therefore, is acceptable.

4.6 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses

The interior surface of a concrete containment structure is lined with thin metallic plates to provide a leak-tight barrier against the uncontrolled release of radioactivity to the environment. The liner plates are attached to the concrete containment wall by an anchorage system. The design process assumes that the liner plates do not carry loads. However, normal loads, such as from concrete shrinkage, creep, and thermal changes, imposed on the concrete containment structure, are transferred to the liner plates through the anchorage system. Internal pressure and temperature loads are directly applied to the liner plates. Thus, under design-basis conditions, the liner plate could experience significant strains.

The containment liner plates, metal containments, penetration sleeves, and penetration bellows may be designed in accordance with requirements of the ASME B&PV Code Section III. If a plant's code of record requires a fatigue analysis, then this analysis may be a TLAA and must be evaluated in accordance with 10 CFR 54.21(c)(1) to ensure that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

4.6.1 Fatigue Analysis of Primary Containment, Attached Piping, and Components

4.6.1.1 Summary of Technical Information in the Application

Section 4.6.1, stated that the HCGS primary containment was designed in accordance with the ASME Code Section III. Subsequently, during large-scale testing for the Mark III containment system and the in-plant testing for Mark I primary containment systems, new suppression chamber hydrodynamic loads were identified. Therefore, re-evaluation of the primary containment structure was performed in two parts: generic analyses applicable to each of the several classes of BWR containments, and Mark I Containment Program plant-unique analyses. The Mark I analyses are detailed in the HCGS Plant Unique Analysis Report (PUAR) and assume 596 single safety relief valve (SRV) lifts and 370 multiple SRV lifts.

In the LRA, the applicant also stated that to address license renewal requirements, the historical number of SRV lifts was researched to determine the number of SRV lifts from 1986 (initial plant startup testing) through the end of 2007. Based on this research, the applicant has projected 592 single SRV lifts and 26 multiple lifts for 60 years of operation. Both of these numbers are below the values assumed in the Mark I analyses (596 single SRV lifts and 370 multiple SRV lifts). The applicant further stated that the associated CUF are projected to be within the original design assumptions and that all relevant plant transient events will be tracked to ensure that the CUF remains less than 1.0 for all monitored components. This conclusion is based on a comprehensive review governing fatigue analyses of the bounding set of primary containment locations. The scope of the analyses includes the pressure suppression chamber (shells and welds), the drywell-to-pressure suppression chamber vents (header and downcomers), SRV discharge piping, other piping attached to the pressure suppression chamber, penetrations, and vent bellows. The applicant has dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(iii), using the Metal Fatigue of Reactor Coolant Pressure Boundary Program to monitor the number of cycles of the design transients and the corresponding CUF for critical primary containment components.

4.6.1.2 Staff Evaluation

The staff reviewed LRA Section 4.6.1 and found that the number of cycles and the associated CUF are projected to be within the original design assumptions. The CUF for the different components of the HCGS primary containment are listed in the LRA Table 4.6.1-1. The maximum design-basis CUF of 0.98 for 40-year life is for the drywell shell at vent line penetration. Therefore, the applicant has committed to monitor the number of cycles at this particular location prior to the period of extended operation.

For all other locations, the design-basis CUF for 40-year life is less than 0.80, and the estimated CUF, based on projected number of cycles for 60 years of operations is not more than 0.366. However, the applicant plans to track all relevant plant transient events to ensure that the CUF remains less than 1.0 for all monitored components. The applicant will perform validation for primary containment locations by monitoring the design-basis CUF ratios that exceed 0.4 (or 40 percent of the allowable value). For locations with a CUF less than 0.4, a 20-year increase in service life will not raise the CUF significantly close to the allowable value of 1.0 and will not be monitored.

Therefore, the staff has determined that the effects of aging on the primary containment components will be adequately managed for the period of extended operation. The Metal Fatigue of Reactor Coolant Pressure Boundary Program will monitor the number of cycles of the design transients and the corresponding CUF for critical primary components, thus, managing the effects of aging due to fatigue on the primary containment, in accordance with 10 CFR 54.21(c)(1)(iii). The staff's evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.19.

4.6.1.3 UFSAR Supplement

LRA Section A.4.6.1 provides the UFSAR supplement for the fatigue analyses of primary containment, attached piping, and components TLAA evaluation. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 4.6-1. The staff concludes that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

4.6.1.4 Conclusion

Based on its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation and found that the Metal Fatigue of Reactor Coolant Pressure Boundary Program will monitor the effects of aging due to fatigue on the primary containment, attached piping, and components in accordance with 10 CFR 54.21(c)(1)(iii). The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and therefore, is acceptable.

4.6.2 Primary Containment Process Penetrations and Bellows Fatigue Analysis

4.6.2.1 Summary of Technical Information in the Application

In LRA Section 4.6.2, the applicant stated that the primary containment process piping penetrations meet ASME Code Section III, Class 1 or 2 requirements, as applicable. The primary containment process piping penetrations use flued heads to connect the process piping to the drywell sleeves. The flued heads for the ASME Code Section III, Class 1 process piping systems have been analyzed for fatigue. These Class 1 fatigue analyses are based upon thermal cycles specified for the 40-year life of the plant and have, therefore, been identified as TLAAs requiring evaluation for the period of extended operation. The applicant further stated that the maximum 40-year CUF ratio (CUF/allowable) identified for any of these penetrations is 0.957 for feedwater penetrations P-2A and P-2B.

Since these two penetration locations have CUF ratios that exceed 0.4, the triple flued heads will be included in the Metal Fatigue of Reactor Coolant Pressure Boundary Program as a program enhancement. All relevant plant transient events will be tracked to ensure that the CUF remains less than 0.1 for these two triple flued heads. Furthermore, the applicant stated that all other governing penetration fatigue analyses have been reviewed, and the CUF ratios for all other penetrations are less than 0.4.

The applicant also stated that the penetration design includes a flexible bellows to seal the triple flued head to the drywell penetration sleeve. The flexible bellows were designed in accordance with ASME Code Section III, Class 2 requirements. The applicant further stated that analyses for the flexible bellows were reviewed. It was determined that the fatigue usage experienced by the flexible bellows was bounded by the corresponding attached triple flued head. Monitoring of the fatigue usage for the triple flued heads will provide assurance that no flexible bellows will exceed its allowable value. The applicant has dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(iii), using the Metal Fatigue of Reactor Coolant Pressure Boundary Program to monitor the number of cycles of the design transients and the CUF for the triple flued heads.

4.6.2.2 Staff Evaluation

The staff reviewed LRA Section 4.6.2 to verify, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The staff noted that the maximum 40-year CUF ratio identified for any of these penetrations is 0.957 for feedwater penetrations P-2A and P-2B. However, the applicant has stated that since these two penetration locations have CUF ratios that exceed 0.4, the triple flued heads will be included in the Metal Fatigue of Reactor Coolant Pressure Boundary Program as a program enhancement. All relevant plant transient events will be tracked to ensure that the CUF remains less than 0.1 for these two triple flued heads.

In a letter dated June 1, 2010, the staff issued RAI 4.6-1 requesting that the applicant explain how all relevant plant transient for feedwater penetrations P-2A and P-2B will be tracked to ensure that the CUF remains less than 0.1.

In its response to RAI 4.6-1 dated June 24, 2010, the applicant stated that feedwater penetrations are located in a no-break zone for the HELB. Therefore, their allowable CUF is

0.10. The design CUF is divided by the allowable CUF to determine the CUF ratio. The applicant further stated that the 40-year design fatigue value for these two penetrations is 0.0957 and CUF ratio of 0.957. Therefore, these two penetrations will be monitored using the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

The staff's evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.19. The staff reviewed the applicant's response to RAI 4.6-1 and found it acceptable because the applicant's use of design CUF of 0.10 is consistent with UFSAR Section 3.6.2.1.1.1. According to UFSAR Section 3.6.2.1.1.1, the feedwater system piping penetrations are not designed to withstand the loadings resulting from a HELB and are designed for a CUF of less than 0.1 associated with normal, upset, and testing conditions. Therefore, the applicant's commitment to monitor these two penetrations using the Metal Fatigue of Reactor Coolant Pressure Boundary Program is acceptable.

4.6.2.3 UFSAR Supplement

LRA Section A.4.6.2 provides the UFSAR supplement for the fatigue analyses of primary containment process penetrations and bellows TLAA evaluation. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Tables 4.6-1. The staff concludes that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

4.6.2.4 Conclusion

Based on its review, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation and found that the triple flued heads will be included in the Metal Fatigue of Reactor Coolant Pressure Boundary Program as a program enhancement to monitor the effects of aging due to fatigue on the primary containment process piping penetrations and bellows in accordance with 10 CFR 54.21(c)(1)(iii). The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and therefore, is acceptable.

4.6.3 Vent Line Bellows

4.6.3.1 Summary of Technical Information in the Application

In LRA Section 4.6.3, the applicant stated that the fatigue evaluation for the vent line bellows that seal the drywell shell to the vent lines, which connect to the torus, is based on the number of cycles assumed for the 40-year life of the plant. The applicant also stated that the originally specified number of thermal load and internal pressure cycles was 150 cycles and the bellows have a rated capacity of 230 cycles at maximum displacements for normal operating conditions. The applicant further stated that the maximum number of startup and shutdown cycles expected for 60 years of operation at HCGS is 180 cycles, based on LRA Table 4.3.1-1.

The applicant stated that since the allowable number of cycles, at maximum displacements for normal operating conditions, are greater than those projected for 60 years, the fatigue evaluation for the vent line bellows remains valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.6.3.2 Staff Evaluation

The staff reviewed LRA Section 4.6.3 to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation. The staff noted that in LRA Table 4.3.1-1, the startup and shutdown cycles as of December 31, 2007, were 79 cycles and the projected cycles for 40 years and 60 years were 125 cycles and 174 cycles, respectively, based on the number of events as of December 31, 2007, and the trends from the past 12 years of the actual plant operation. The rated capacity of the bellows is 230 cycles at maximum displacements for normal operating conditions.

Based on its review, the staff finds that the fatigue evaluation for the vent line bellows remains valid for the period of extended operation since the allowable number of cycles, at maximum displacements for normal operating conditions, is greater than those projected for 60 years.

4.6.3.3 UFSAR Supplement

LRA Section A.4.6.3 provides the UFSAR supplement for the fatigue analyses of the vent line bellows TLAA evaluation. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 4.6-1. The staff concludes that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

4.6.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), for the vent line bellows fatigue TLAA, the analyses remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and therefore, is acceptable.

4.7 Other Plant-Specific Time Limited Aging Analyses

There are certain plant-specific safety analyses that may have been based on an explicitly assumed 40-year plant life and may, therefore, be TLAAs. Pursuant to 10 CFR 54.21(c), the applicant is required to evaluate TLAAs.

This subsection is the staff's review of other plant-specific TLAAs that the applicant has evaluated in the LRA.

4.7.1 Crane Load Cycle Limit

4.7.1.1 Summary of Technical Information in the Application

In LRA Section 4.7.1, the applicant stated that the reactor building polar crane and the service water intake structure gantry crane are within the scope of license renewal and have been identified as having a TLAA, which requires evaluation for 60 years as follows:

Reactor Building Polar Crane. The applicant stated that the reactor building polar crane at HCGS is designed to meet or exceed the design fatigue requirements of the Crane Manufacturers Association of America (CMAA) Specification 70, "Specifications for Top Running Bridge and Gantry Type Multiple Girder Electric Overhead Traveling Cranes." The applicant also stated that the polar crane was designed for a minimum of 100,000 load cycles, corresponding to the criteria of CMAA Specification 70 for service Class A. The applicant further stated that the total number of lifts for the polar crane has been estimated to be 2,720 cycles for the total life of the plant, including the period of extended operation associated with license renewal. The applicant stated that this estimated data is less than the minimum allowable design value of 100,000 cycles.

Service Water Intake Structure Gantry Crane. The applicant stated that the service water intake structure gantry crane purchasing specification required that the crane conform to the latest edition CMAA, Specification 70 for electric overhead traveling cranes, and was designed for 100,000 to 500,000 load cycles. The applicant also stated that a review of service water intake structure gantry crane operation during the current life of the plant, including an estimated 200 lifts during original construction, indicates that the total number of lifts is less than 600 cycles. The applicant further stated that an average rate of 32 lifts per year over the course of 60 years results in the service water intake structure gantry crane experiencing 1,920 lifts. The applicant stated that these estimated data are less than the minimum allowable design value of 100,000 cycles.

The applicant dispositioned these TLAAs in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.7.1.2 Staff Evaluation

The staff reviewed LRA Section 4.7.1 to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation. The staff noted that in LRA Section 2.3.3.8, "Scoping and Screening," the applicant listed a total of 18 cranes and hoists as within the scope of license renewal. LRA Table 3.3.2-8 requires a TLAA for component group

"Crane/Hoist Bridge/Trolley Girders" for aging management due to cumulative fatigue damage and fatigue per the GALL Report recommendations.

Therefore, by letter dated June 1, 2010, the staff issued RAI 4.7-1 requesting that the applicant explain why the reactor building polar crane and the service water intake structure gantry crane are the only two cranes with a TLAA when there are 18 cranes within the scope of license renewal.

In its response to RAI 4.7-1, dated June 24, 2010, the applicant stated that a review of potential TLAAs related to the cranes and hoists for the LRA did not identify calculations or analyses for any of the in-scope cranes that involved time-limited assumptions. Structural calculations were provided by the vendors during original design and construction of HCGS for the reactor building polar crane and service water intake gantry crane. These calculations, along with other documents for the two cranes, were found to contain references to procurement specifications that require the cranes to be designed in accordance CMAA Specification 70, "Specifications for Top Running Bridge and Gantry Type Multiple Girder Electric Overhead Traveling Cranes." As a result, these two cranes were conservatively considered to have TLAAs and evaluated with a service class consisting of 100,000 to 500,000 load cycles.

In its response of June 24, 2010, the applicant also stated that only other in-scope girders for HCGS are associated with the main steam tunnel underhung bridge crane and diesel generator underhung cranes. These cranes are nonsafety-related, but were evaluated as potential TLAAs; however, no potential calculations or analyses were identified that meet the definition of TLAA per 10 CFR 54.3(a). The applicant further stated that the other in-scope cranes are simple devices and do not have a TLAA.

Based on the review of LRA Section 4.7.1 and the applicant's response to RAI 4.7-1, the staff has concluded that the effects of aging on the in-scope cranes has been properly evaluated and will be adequately managed for the period of extended operation because:

The reactor building polar crane is designed, and complies, with the CMAA Specification 70 and Class A requirement. The crane, therefore, was designed for a minimum of 100,000 load cycles for a 40-year life. The number of maximum rated load cycles for the polar crane originally projected for a 60-year life has been estimated to be 2,720, which are significantly less than the design limit of 100,000 cycles.

The service water intake structure gantry crane purchasing specification required that the crane conform to the latest edition of design for 100,000 to 500,000 load cycles. The number of estimated rated load cycles for the service water intake structure gantry crane for a 60-year life has been estimated to be 1,920, which is significantly less than the design limit of 100,000 cycles.

The main steam tunnel underhung bridge crane and diesel generator underhung cranes are: (1) nonsafety-related and original design-basis documents do not include any calculation or analysis, (2) designed and procured to conform with CMAA Specification 70 and Class A requirements, and (3) less frequently used as compared to the reactor building polar crane. Therefore, the main steam tunnel underhung bridge crane and diesel generator underhung cranes do not require TLAAs per 10 CFR 54.3(a).

The other 14 in-scope cranes are simple devices consisting of hoists and monorails, do not have any bridge or trolley girders, and do not require TLAAs in accordance with 10 CFR 54.3(a).

4.7.1.3 UFSAR Supplement

LRA Section A.4.7.1 provides the UFSAR supplement for the load cycle limits of reactor building polar crane and service water intake structure gantry crane TLAA evaluation. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Section 4.7.3.2. The staff concludes that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

4.7.1.4 Conclusion

Based on its review, as discussed above, the staff concludes, that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that for fatigue load cycle limits of the reactor building polar crane and the service water intake structure gantry crane, the analyses remain valid for the period of extended operation. The other in-scope cranes are not frequently used and do not require a TLAA in accordance with 10 CFR 54.3(a). The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and therefore, is acceptable.

4.7.2 Refueling Bellows Fatigue

4.7.2.1 Summary of Technical Information in the Application

LRA Section 4.7.2 discusses refueling bellows fatigue. The applicant stated that a fatigue analysis was performed for each of the two bellows that seal the drywell bulkhead and RV and the drywell bulkhead and drywell shell for refueling operations. The applicant also stated that fatigue analysis for each of these bellows is based on the number of cycles assumed for the 40-year life of the plant; therefore, these analyses satisfy the criteria of 10 CFR 54.3(a) and are evaluated as TLAAs in accordance with 10 CFR 54.21(c).

The applicant stated that the bulkhead-to-drywell bellows exhibited the highest calculated fatigue usage of 0.124. The applicant further stated that fatigue usage for both bellows was determined by the number of cycles of startup and shutdown and the number of flood-up events at each refueling outage. The applicant indicated that the fatigue analysis assumed 360 cycles for startup and shutdown and reflood over the life of the plant.

The applicant also stated that, as listed in LRA Table 4.3.1-1, the maximum number of startup and shutdown cycles expected for 60 years of operations at HCGS is 180 cycles for startup and shutdown and 55 cycles for refueling operations, for a total of 235 cycles. The applicant concluded that since the number of cycles used in the analyses for these events are greater than those projected for 60 years, the fatigue analyses for the refueling bellows remain valid for the period of extended operation. The applicant dispositioned this refueling bellows fatigue TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.7.2.2 Staff Evaluation

The staff reviewed the TLAA in LRA Section 4.7.2 against the acceptance guidance in SRP-LR Section 4.7.3.1.1 for dispositioning plant-specific TLAAs in accordance with 10 CFR 54.21(c)(1)(i). LRA Section 4.7.2 states that the refueling bellows were designed for 360 cycles for startup and shutdown and reflood over the life of the plant. The staff noted that the applicant has projected the number of startup and shutdown and reflood cycles to the end of the period of extended operation to be 235 cycles.

The staff reviewed LRA Table 4.3.1-1 to determine how the applicant projected the number of cycles for 60 years. The staff determined that the applicant has counted the number of events as of December 31, 2007, and projected this number forward for 60 years based on trends from the past 12 years (9 operating cycles) of actual plant operation. The staff determined that the applicant appropriately projected the number of cycles for 60 years. Based on this consideration, the staff finds the applicant's claim that the refueling bellows will maintain their structural integrity during the period of the extended operation acceptable because: (1) the maximum number of startup and shutdown, and reflood cycles projected for 60 years (e.g., 235 cycles) have been demonstrated to be bounded by the 360 cycle limit assumed in the refueling bellows fatigue analysis; (2) the highest calculated fatigue usage for 40-year life is 0.124, which is significantly less than the limit of 1.0; and (3) the analysis demonstrates compliance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(i), in that the current analysis has been demonstrated to remain valid for the period of extended operation.

4.7.2.3 UFSAR Supplement

LRA Section A.4.7.2 provides the UFSAR supplement for the load cycle limits of refueling bellows fatigue TLAA evaluation. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Section 4.7.3.2. The staff concluded that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

4.7.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the refueling bellows fatigue in the CLB has been demonstrated to remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.3 Neutron Fluence-Induced Bolt Stress Relaxation – Jet Pump Auxiliary Spring Wedges and Slip Joint Clamps

4.7.3.1 Summary of Technical Information in the Application

LRA Section 4.7.3 presents the applicant's evaluation of the bolt stress relaxation in auxiliary spring wedges (installed in 2007 and 2009) and the slip joint clamps (installed on the jet pumps in 2006).

For the auxiliary spring wedge bolts, the original evaluation showed that the preload on the bolts would be acceptable up to a neutron fluence (energy > 1.0 MeV) of 1.07×10^{20} neutrons per square centimeter (n/cm^2) for the 40-year life of the jet pumps. A new analysis has determined that the actual neutron fluence on the auxiliary spring wedge bolts after 60 years of service for the jet pumps at HCGS is below the original 40-year value. Since the projected 60-year neutron fluence on the auxiliary spring wedge bolts is bounded by the initial neutron fluence of 1.07×10^{20} n/cm^2, the analysis remains valid for the period of extended operation.

For the slip joint clamp bolts, the original evaluation showed that the preload on the bolts would be acceptable up to a neutron fluence of 1.50×10^{18} n/cm^2 for the 40-year life of the jet pumps. A new analysis has determined that the actual neutron fluence on the slip joint clamp bolts will reach the bounding fluence of 1.50×10^{18} n/cm^2 after 35.4 EFPY of service for the jet pumps at HCGS.

Since the analysis on the slip joint clamp bolts is not bounding for the period of extended operation, the staff discussed its concern in a telephone call on September 2, 2010. In a letter dated September 9, 2010 (ADAMS Accession No. ML102580031), the applicant committed (Commitment No. 52) to: (1) replace the slip joint clamp at the last refueling outage prior to reaching the bounding value of 35.4 EFPY, or (2) 2 years before reaching the bounding value of 35.4 EFPY, perform an analysis that demonstrates that the function of the component is maintained.

4.7.3.2 Staff Evaluation

The staff reviewed LRA Section 4.7.3 to evaluate that the neutron fluence-induced bolt stress relaxation analyses of the auxiliary spring wedge bolts and slip joint clamp bolts have been projected to the end of the period of extended operation. The applicant performed a new analysis for each of the two cases.

For the first TLAA (the auxiliary spring wedge bolts), the new analysis showed that the projected neutron exposure on the bolts after 60 years of service for the jet pumps will be less than the original, conservative estimate of 1.07×10^{20} n/cm^2 for a 40-year life. Therefore, given the updated analysis, the staff agrees that the current analysis for the auxiliary spring wedge bolts remains valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

For the second TLAA (the slip joint clamp bolts), the new analysis showed that the projected neutron exposure on the slip joint clamp bolts will exceed the original estimate of 1.50×10^{18} n/cm^2 after 35.4 EFPY of service for the jet pumps at HCGS; this TLAA is not bounded by the original analysis for the period of extended operation. Therefore, HCGS will either: (1) replace the slip joint clamp at the last refueling outage prior to reaching the bounding value of 35.4 EFPY; or (2) 2 years before the neutron fluence reaches the bounding value of 35.4 EFPY , perform an analysis that demonstrates that the function of the component is maintained.

Therefore, given the applicant's commitment, the staff agrees that the second TLAA for the auxiliary spring wedge bolts will be managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

4.7.3.3 UFSAR Supplement

LRA Section A.4.7.3 provides the UFSAR supplement of its neutron fluence-induced bolt stress relaxation TLAA evaluation. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description of this type of program as described in SRP-LR Section 4.7.3.2. The staff also notes that the applicant committed in a revised Commitment No. 52 to either: (1) replace the slip joint clamp at the last refueling outage prior to reaching the bounding value of 35.4 EFPY; or (2) 2 years before the neutron fluence reaches the bounding value of 35.4 EFPY, perform an analysis that demonstrates that the function of the component is maintained.

On the basis of its review, the staff finds the summary description of the applicant's actions to address neutron fluence-induced bolt stress relaxation adequate, as required by 10 CFR 54.21(d).

4.7.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the neutron fluence-induced bolt stress relaxation TLAA for the auxiliary spring wedge bolts remains valid for the period of extended operation. For the neutron fluence-induced bolt stress relaxation analysis of the slip joint clamp bolts, the applicant will manage aging, pursuant to 10 CFR 54.21(c)(1)(iii), according to a revised Commitment No. 52. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluations, as required by 10 CFR 54.21(d), and therefore, is acceptable.

4.8 Conclusion for Time-Limited Aging Analyses

The staff reviewed the information in LRA Section 4, "Time-Limited Aging Analyses." On the basis of its review, the staff concludes that the applicant has provided a sufficient list of TLAAs, as defined in 10 CFR 54.3, and that the applicant has demonstrated that: (1) the TLAAs will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i); (2) the TLAAs have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii); or (3) that the effects of aging on intended functions will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii). The staff also reviewed the UFSAR supplement for the TLAAs and finds that the supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, the staff concludes, as required by 10 CFR 54.21(c)(2), that no plant-specific, TLAA-based exemptions are in effect.

With regard to these matters, the staff concludes that there is reasonable assurance that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB and that any changes made to the CLB, in order to comply with 10 CFR 54.29(a), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The NRC staff issued its safety evaluation report (SER) with open items related to the renewal of the operating license for Hope Creek Generating Station (HCGS) on September 30, 2010. On November 3, 2010, the applicant presented its license renewal application, and the staff presented its review findings to the ACRS Plant License Renewal Subcommittee. The staff reviewed the applicant's comments on the SER and completed its review of the license renewal application. The staff's evaluation is documented in an SER that was issued by letter dated March 9, 2011. Subsequently, the staff received additional information from the applicant dated May 19, 2011, regarding the ASME Section XI, Subsection IWE Program which manages the drywell air gap drain lines. Specifically, the applicant noted that, based on boroscope inspections, it could not verify the actual configuration of the drain lines and provided additional enhancements to the ASME Section XI, Subsection IWE Program. The staff revised the SER to reflect the staff's latest evaluation of the applicant's ASME Section XI, Subsection IWE Program and its review is documented in SER Section 3.0.3.2.14.

During the 594th meeting of the ACRS, June 8-10, 2011, the ACRS completed its review of the HCGS license renewal application and the NRC staff's SER. The ACRS documented its findings in a letter to the Commission dated June 16, 2011. A copy of this letter is provided on the following pages of this SER Section.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

June 16, 2011

The Honorable Gregory B. Jaczko
Chairman
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE HOPE CREEK GENERATING STATION

Dear Chairman Jaczko:

During the 584th meeting of the Advisory Committee on Reactor Safeguards, June 8-10, 2011, we completed our review of the license renewal application for the Hope Creek Generating Station (HCGS) and the final Safety Evaluation Report (SER) prepared by the NRC staff. During our 583rd meeting, May 12-14, 2011, we reviewed a previous version of this application and the associated staff SER. Our Plant License Renewal Subcommittee also reviewed this matter during its meeting on November 3, 2010. During these reviews, we had the benefit of discussions with representatives of the NRC staff and PSEG Nuclear, LLC (PSEG or the applicant). We also had the benefit of the documents referenced. This report fulfills the requirement of 10 CFR 54.25 that the ACRS review and report on all license renewal applications.

CONCLUSION AND RECOMMENDATION

1. The programs established and committed to by the applicant to manage age-related degradation provide reasonable assurance that HCGS can be operated in accordance with its current licensing basis (CLB) for the period of extended operation (PEO) without undue risk to the health and safety of the public.

2. The PSEG application for renewal of the operating license of HCGS should be approved.

BACKGROUND AND DISCUSSION

HCGS is a General Electric (GE) Model 4 boiling water reactor (BWR) with a Mark I containment. HCGS is located approximately 40 miles from Philadelphia, Pennsylvania, and 8 miles from Salem, New Jersey. The licensed power output of the unit is 3,840 megawatts thermal with a gross electrical output of approximately 1,268 megawatts electric. PSEG has requested renewal of the HCGS operating license for 20 years beyond the current license term, which expires on April 11, 2026.

In the final SER, the staff documented its review of the license renewal application and other information submitted by the applicant or obtained from the staff audits and inspection at the plant site. The staff reviewed the completeness of the applicant's identification of the structures, systems, and components (SSCs) that are within the scope of license renewal; the integrated plant assessment process; the applicant's identification of the plausible aging mechanisms associated with passive, long-lived components; the adequacy of the applicants Aging Management Programs (AMPs); and the identification and assessment of time-limited aging analyses (TLAAs) requiring review.

In the HCGS license renewal application, PSEG identified the SSCs that fall within the scope of license renewal. For these SSCs, the applicant performed a comprehensive aging management review. Based on this review, the applicant will implement 47 AMPs for license renewal, of which 33 are existing programs and 14 are new programs. Fifteen of the programs are enhanced and eight programs have exceptions compared with the corresponding programs described in the Generic Aging Lessons Learned (GALL) Report. Six of the programs are plant specific programs that do not have counterparts in the GALL Report. The PSEG application either demonstrates consistency with the GALL Report or documents deviations to the approaches specified in the Report. We have reviewed the exceptions and agree with the staff that they are acceptable.

The staff conducted two license renewal audits and an inspection at HCGS. The audits verified the appropriateness of the scoping and screening methodology, aging management review, and associated AMPs. The inspection verified that the license renewal requirements are appropriately implemented. Based on the audit and inspection, the staff concluded in the final SER that the proposed activities will reasonably manage the effects of aging of SSCs identified in the application and that the intended functions of these SSCs will be maintained during the PEO. We agree with these conclusions.

Industry operating experience documents instances of corrosion on inaccessible exterior surfaces of the drywell shell of GE BWR Mark I containments. PSEG performed ultrasonic thickness (UT) measurements, for the drywell shell in 2007 and 2009. The results of these inspections showed no loss of material due to corrosion. A small reactor cavity leak was identified in 2009 during the refueling outage. The leak only occured when the reactor cavity was flooded. The probable leakage path is through a weld defect in the reactor cavity seal plate through the air gap between the drywell shell and the concrete shield wall. Some leakage exited the air gap through an instrument penetration sleeve in the concrete shield wall and formed a small puddle on the torus room floor.

Borescope inspections indicated that wetting of the concrete occurred over about a 30° azimuth span. Such leakage could collect at the base of the gap between the shell and the shield wall. There were supposed to be drain lines at the base of this gap to prevent moisture collection, but borescope examinations of each of the four drain lines showed that all of the drain lines were blocked. Probes inserted into the exit of one drain line in the torus room indicate that the line is blocked about six feet from the inner surface of the concrete shield wall. The configuration of the other three drains is not known at this time, but all of the drains are, and probably have been, nonfunctional since original construction. Thus, potential moisture from leaks could collect at the base of the drywell gap and wet a ring of the drywell shell about 1.4 feet in height before spilling out of the openings around the drywell vent lines. However, no spillage has been observed.

PSEG has made many UT measurements around the drywell shell at the base of the air gap and up the drywell shell opposite the known wetted area of the concrete. All the measured thicknesses, except for a small region at the base of the drywell air gap in the region where wetting of the concrete could be observed at higher elevations, are above the nominal thicknesses and the design thicknesses. The minimum measured thickness is well above that assumed in the design analyses.

The AMP for the drywell shell is based on ASME Section XI, Subsection IWE. PSEG has committed to a number of enhancements beyond this program. They will continue to search for the source of the reactor cavity water leakage and repair it, if practical, before the PEO. PSEG will verify that the reactor cavity seal rupture drain lines are open. The program also commits to the establishment of drainage from the bottom of the air gap drains and provides for augmented UT examinations of the drywell shell to provide assurance of the integrity of the drywell shell.

To ensure compliance with these commitments, the staff has added two license conditions:

The first of these requires the applicant to establish drainage capability from the bottom of the drywell air gap from all four quadrants. Until drainage is established, the applicant will perform borescope examinations and UT measurements. The applicant will monitor penetration sleeve, J13, daily for water leakage when the reactor cavity is flooded and will submit a report to the staff summarizing the results from the borescope examinations, UT measurements, and leakage detected from the penetration.

The second license condition requires PSEG to submit a report to the staff when drainage has been established from the bottom of the air gap in all four quadrants. PSEG will also perform UT measurements during the next three refueling outages and submit a report to the staff summarizing the results from the UT measurements.

Based on this enhanced AMP for the drywell shell, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions of the primary containment will be maintained consistent with the CLB for the PEO. We concur with the staff's conclusion.

Inaccessible medium-voltage cables in certain manholes at HCGS have been exposed to significant moisture, i.e., in standing water for more than a few days. The staff has identified water in manholes as a generic, current operating plant issue in Information Notice 2002-12, “Submerged Safety-Related Electrical Cables,” dated March 21, 2002, and Generic Letter 2007-01, “Inaccessible or Underground Power Cable Failures That Disable Accident Mitigation Systems or Cause Plant Transients,” dated February 7, 2007. During the current period of operation, this issue is being addressed through the reactor oversight process, in accordance with the requirements of 10 CFR Part 50.

The problem is exacerbated at HCGS because the service water cable vaults are not easily accessible. They have 60-ton concrete blocks as covers. In addition, there are sections of in-scope cables that go in duct banks below the elevation of the manholes. Operating experience suggests that the moisture ingress is event-driven, i.e., infiltration from storms. Physical modifications have been made to the service water cable vault covers to allow more frequent inspection and dewatering. PSEG is also making repairs to try to reduce inleakage. Despite a history of water intrusion, HCGS has no history of failures of in-scope inaccessible low and medium voltage power cables.

PSEG has committed to implement a Non-EQ Inaccessible Medium-Voltage Cables Program. This program includes (1) testing of in-scope, inaccessible cables (480 volts (V); 4,160V; and 13,800V) that are exposed to significant moisture, and (2) inspection of cable vaults, including subsequent removal of accumulated water if required, as a preventive measure to minimize the potential exposure of in-scope cables to significant moisture.

In-scope cables will be subject to electrical performance testing to ensure suitability for operation. The cables will be tested to detect deterioration of the insulation system due to wetting, using tests such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed. PSEG currently uses Tan δ testing on in-scope medium voltage cables and insulation resistance testing on in-scope low voltage power cables. The cable test frequency will be established based on test results and industry operating experience. The maximum time between tests, however, will not exceed six years.

Manholes for in-scope cables are now being monitored on a weekly basis. PSEG has committed to perform sufficient manhole and cable vault inspections prior to the PEO so that proper inspection frequencies can be established to minimize the exposure of power cables to significant moisture during the PEO. The maximum time between inspections will be no more than one year.

The staff has determined that the Non-EQ Inaccessible Medium-Voltage Cables Program, if implemented as committed to by the applicant, will ensure that the aging affects on inaccessible power cables will be adequately managed during the PEO. We agree with this conclusion.

The Buried Piping Inspection Program provides aging management of carbon steel, ductile cast iron, and gray cast iron buried piping susceptible to general corrosion, pitting, crevice corrosion, and microbially induced corrosion. There are no in–scope buried tanks. The program relies on the visual inspection of excavated piping, including the associated coatings and wrappings. Portions of the carbon steel piping are cathodically protected. The rectifiers for the cathodic protection system are monitored on a semi-monthly basis and inspected and tested on an annual basis. For the past five years, cathodic protection availability has exceeded 90 percent.

There have been no leaks of buried in-scope piping at HCGS as a result of external piping corrosion, and inspections of coatings that have occurred during opportunistic inspections of ductile cast iron fire protection piping have also found the coatings to be in acceptable condition. All buried piping has been risk-ranked in accordance with NACE and EPRI guidelines, and PSEG is implementing the NEI Industry Initiative on Buried Piping.

The applicant has committed to perform at least one opportunistic or focused excavation and inspection on piping from each of the material types during each 10 year period, beginning 10 years prior to entry into the PEO. Reinforced concrete piping is addressed under a different program, but will be subject to the same inspection requirement. A second opportunistic or focused excavation and inspection on a carbon steel piping segment, which is not cathodically protected, will be performed during each 10 year period, beginning 10 years prior to entry into the PEO. A different segment will be inspected in each 10 year period.

The staff has concluded that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the PEO, as required by 10 CFR 54.21(a)(3). We concur with this conclusion.

The applicant identified the systems and components requiring TLAAs and reevaluated them for the PEO. The staff concluded that the applicant has provided an adequate list of TLAAs. Further, the staff concluded that the applicant has met the requirements of the License Renewal

Rule by demonstrating that the TLAAs will remain valid for the PEO, or that the TLAAs have been projected to the end of the PEO, or that the aging effects will be adequately managed for the PEO.

We agree with the staff that there are no issues related to the matters described in 10 CFR 54.29(a)(1) and (a)(2) that preclude renewal of the operating license for HCGS. The programs established and committed to by PSEG provide reasonable assurance that the HCGS can be operated in accordance with its current licensing basis for the PEO without undue risk to the health and safety of the public. The PSEG application for renewal of the operating license for HCGS should be approved.

Sincerely,

/RA/

Said Abdel-Khalik
Chairman

References:

1. NRC Safety Evaluation Report Related to the License Renewal of Hope Creek Generating Station, June 2011 (ML11158A166)

2. NRC Safety Evaluation Report Related to the License Renewal of Hope Creek Generating Station, March 2011 (ML110690244)

3. PSEG Nuclear LLC License Renewal Application for Hope Creek Generating Station, August 18, 2009, (ML092430375: Cover Latter; ML092430373: LRA Section1 thru Section 3.3; ML092430374: LRA Section 3.4 thru Appendix D)

4. Letter from P. Davison, PSEG Nuclear, LLC: Response to NRC Draft Request for Additional Information B.2.1.28-4 related to the ASME Section XI Subsection IWE Aging Management Program associated with the Hope Creek Generating Station License Renewal Application, May 19, 2011 (ML11144A016)

5. NRC Scoping and Screening Audit Summary Regarding Hope Creek Generating Station License Renewal Application, August 19, 2010 (ML102100544)

6. NRC Audit Report Regarding Hope Creek Generating Station License Renewal Application, September 3, 2010 (ML101660452)

7. NRC License Renewal Inspection Report 05000272/2010010, 05000311/2010010, 05000354/2010010, October 14, 2010 (ML102871030)

8. NRC NUREG-1800, Revision 1, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” September 2005 (ML052700171)

9. NRC NUREG-1801, Volumes 1 & 2, Revision 1, “Generic Aging Lessons Learned Report,” September 2005 (ML052700171)

10. NRC Information Notice 2002-12, “Submerged Safety-related Electrical Cables,” dated March 21, 2002 (ML020790238)

11. NRC Generic Letter 2007-01, “Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients,” dated February 7, 2007 (ML070360665)

SECTION 6

CONCLUSION

The staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) reviewed the license renewal application (LRA) for Hope Creek Generating Station (HCGS) in accordance with NRC regulations and NUREG-1800, Revision 1, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” dated September 2005. Title 10, Section 54.29, of the *Code of Federal Regulations* (10 CFR 54.29) sets the standards for issuance of a renewed license.

On the basis of its review of the LRA, the staff determines that the requirements of 10 CFR 54.29(a) have been met.

The staff notes that any requirements of 10 CFR Part 51, Subpart A is documented in Supplement 45 to NUREG-1437, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS),” “Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2.”

APPENDIX A

HOPE CREEK GENERATING STATION LICENSE RENEWAL COMMITMENTS

During the review of the Hope Creek Generating Station (HCGS), license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff), PSEG Nuclear, LLC (PSEG or the applicant) made commitments related to aging management programs (AMPs) to manage aging effects of structures and components (SCs) prior to the period of extended operation. The following table lists these commitments, along with the implementation schedules and the sources for each commitment.

APPENDIX A: HCGS LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	A.2.1.1	Ongoing	LRA Section B.2.1.1 August 18, 2009
2	Water Chemistry	A.2.1.2	Ongoing	LRA Section B.2.1.2 August 18, 2009
3	Reactor Head Closure Studs	A.2.1.3	Ongoing	LRA Section B.2.1.3 August 18, 2009
4	BWR Vessel ID Attachment Welds	A.2.1.4	Ongoing	LRA Section B.2.1.4 August 18, 2009
5	BWR Feedwater Nozzle	A.2.1.5	Ongoing	LRA Section B.2.1.5 August 18, 2009
6	BWR Control Rod Drive Return Line Nozzle	A.2.1.6	Ongoing	LRA Section B.2.1.6 August 18, 2009
7	BWR Stress Corrosion Cracking is an existing program that will be enhanced to include: 1. For the components within the scope of the BWR Stress Corrosion Cracking program, resistant materials will be used for new and replacement components. This includes low carbon stainless piping and stainless steel weld material limited to a maximum carbon content 0.035 wt% and a minimum ferrite content of 7.5%.	A.2.1.7	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.7 August 18, 2009
8	BWR Penetrations	A.2.1.8	Ongoing	LRA Section B.2.1.8 August 18, 2009

APPENDIX A: HCGS LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
9	BWR Vessel Internals Existing program is credited. PSEG is committed to implement the BWRVIP guidelines for Hope Creek as follows: • PSEG will inform the NRC staff of any decision to not fully implement a BWRVIP guideline approved by the staff. • PSEG will notify the staff if changes are made to the RPV and its internals' programs that affect the implementation of the BWRVIP guideline. • PSEG will submit any deviation from the existing flaw evaluation guidelines that are specified in the BWRVIP guideline.	A.2.1.9	Ongoing	LRA Section B.2.1.9 August 18, 2009
10	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless steel (CASS) is a new program that will provide for aging management of CASS reactor internal components within the scope of license renewal. The program will include a component specific evaluation of the loss of fracture toughness in accordance with the specified criteria. For those components where loss of fracture toughness may affect function of the component, a supplemental inspection will be performed.	A.2.1.10	Program to be implemented prior to the period of extended operation.	LRA Section B.2.1.10 August 18, 2009
11	Flow-Accelerated Corrosion	A.2.1.11	Ongoing	LRA Section B.2.1.11 August 18, 2009
12	Bolting Integrity Program is an existing program that will be enhanced to include: 1. In the following cases, bolting material should not be reused: a. Galvanized bolts and nuts, b. ASTM A490 bolts; and c. Any bolt and nut tightened by the turn of nut method.	A.2.1.12	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.12 August 18, 2009
13	Open-Cycle Cooling Water System	A.2.1.13	Ongoing	LRA Section B.2.1.13 August 18, 2009

APPENDIX A: HCGS LICENSE RENEWAL COMMITMENTS

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
14	Closed-Cycle Cooling Water System is an existing program that will be enhanced to include: 1. New recurring tasks will be established for enhancing the performance monitoring of the Closed Cycle Cooling Water System. 2. New recurring tasks will be established for enhancing the performance monitoring of the Chilled Water System. 3. A one-time inspection of selected Closed-Cycle Cooling Water program components in stagnant flow areas will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water program. 4. A one-time inspection of selected Closed-Cycle Cooling Water program chemical mixing tanks and associated piping will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water program on the interior surfaces of the tanks and associated piping. 5. The program will be enhanced such that the plant auxiliary building chilled water system, which is part of the Control Area Chilled Water System, will comply with the pure water control program in accordance with EPRI 1007820 prior to the period of extended operation. 6. A one-time inspection of selected Control Area Chilled Water System components, including the plant auxiliary building chilled water system, will be conducted to confirm the effectiveness of the Closed-Cycle Cooling Water program.	A.2.1.14	Program to be enhanced and one-time inspections to be performed prior to the period of extended operation.	LRA Section B.2.1.14 August 18, 2009

APPENDIX A: HCGS LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
15	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems is an existing program that will be enhanced to include: 1. Visual inspection of structural components and structural bolts for loss of material due to general, pitting, and crevice corrosion and structural bolting for loss of preload due to self-loosening. 2. Visual inspection of the rails in the rail system for loss of material due to wear. 3. The acceptance criteria will be enhanced to require evaluation of significant loss of material due to corrosion for structural components and structural bolts, and significant loss of material due to wear of rail in the rail system.	A.2.1.15	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.15 August 18, 2009
16	Compressed Air Monitoring	A.2.1.16	Ongoing	LRA Section B.2.1.16 August 18, 2009
17	Fire Protection is an existing program that will be enhanced to include: 1. The routine inspection procedures will be enhanced to provide additional inspection guidance to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. 2. The fire pump supply line functional tests will be enhanced to provide specific guidance for examining exposed external surfaces of the fire pump diesel fuel oil supply line for corrosion during pump tests. 3. The Halon and Carbon Dioxide fire suppression system functional test procedures will be enhanced to include visual inspection of system piping and component external surfaces for signs of corrosion or other age related degradation, and for mechanical damage. The functional test procedures will also be enhanced to include acceptance criteria stating that identified corrosion or mechanical damage will be evaluated, with corrective action taken as appropriate.	A.2.1.17	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.17 August 18, 2009 Hope Creek Letter LR-N10-0190 RAI B.2.1.17-02 June 14, 2010

APPENDIX A: HCGS LICENSE RENEWAL COMMITMENTS

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
18	Fire Water System is an existing program that will be enhanced to include: 1. The Fire Water System aging management program will be enhanced to inspect selected portions of the water based fire protection system piping located aboveground and exposed to the fire water internal environment by non-intrusive volumetric examinations. These inspections shall be performed prior to the period of extended operation and will be performed every 10 years thereafter. 2. The Fire Water System aging management program will be enhanced to replace or perform 50-year sprinkler head inspections and testing using the guidance of NFPA-25 “Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems” (2002 Edition), Section 5-3.1.1. These inspections will be performed prior to the 50-year in-service date and every 10-years thereafter.	A.2.1.18	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	LRA Section B.2.1.18 August 18, 2009
19	Aboveground Steel Tanks is an existing program that will be enhanced to include: 1. The program will be enhanced to include internal UT measurements to measure the wall thickness on the bottom of the tanks supported on a fiber pad on top of the concrete foundation (Fire Water Storage Tanks). Measured wall thickness will be monitored and trended if significant material loss is detected. These thickness measurements of the tank bottom will be taken and evaluated against design thickness and corrosion allowance to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation. 2. The program will be enhanced to provide routine visual inspections of the carbon steel tanks external surfaces (Fire Water Storage Tanks, Fire Diesel Fuel Oil Tank and 17-Ton CO_2 Storage Tank), including removal of tank insulation from the Fire Water Storage tank to detect degradation. These inspections will be performed to detect degraded paint and coatings, and any resulting metal degradation, prior to loss of the tank intended function.	A.2.1.19	Program to be enhanced prior to the period of extended operation. Tank bottom UT inspections will also be performed prior to the period of extended operation.	LRA Section B.2.1.19 August 18, 2009

APPENDIX A: HCGS LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
20	Fuel Oil Chemistry is an existing program that will be enhanced to include: 1. Equivalent requirements for fuel oil purity and fuel oil testing as described by the Standard Technical Specifications. 2. Addition of biocides, stabilizers and corrosion inhibitors as determined by fuel oil sampling or inspection activities. 3. Internal inspection of Diesel Fire Pump Fuel Oil 280-gallon tank (T-565) using visual inspections and ultrasonic thickness examination of tank bottom. 4. Quarterly water and sediment multilevel sampling on the Diesel Fuel Oil Storage Tanks identified in A.2.1.20 5. Internal inspection of the Diesel Fuel Oil Storage Tanks identified in A.2.1.20 using visual inspections and ultrasonic thickness examination of tank bottoms. 6. Quarterly particulate sampling of Diesel Fire Pump Fuel Oil 280-gallon tank (T-565). 7. To confirm the absence of any significant aging effects, a one-time inspection of each of the 550-gallon Diesel Fuel Oil Day Tanks will be performed.	A.2.1.20	Program to be enhanced and one-time inspections to be performed prior to the period of extended operation.	LRA Section B.2.1.20 August 18, 2009

APPENDIX A: HCGS LICENSE RENEWAL COMMITMENTS

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
21	Reactor Vessel Surveillance is an existing program that will be enhanced to include: 1. Implement the requirements of BWRVIP-116, “BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal,” including the conditions specified by the NRC in its Safety Evaluation dated February 24, 2006. 2. If future plant operations exceed the limitations specified in RG 1.99, the impact of plant operation changes on the extent of reactor vessel embrittlement will be evaluated and the NRC will be notified. Similarly, if future plant operation exceeds the bounds established by surveillance data that are to determine Upper Shelf Energy or P-T limits, then the impact of plant operation changes on the extent of reactor vessel embrittlement will be evaluated and the NRC will be notified. Additionally, when all the surveillance capsules are removed, then operating restrictions will be established to ensure that the plant is operated within the conditions to which the surveillance capsules were exposed. If the reactor vessel exposure conditions (neutron flux, spectrum, irradiation temperature, etc.) are altered, then the basis for the projection to 60 years is reviewed; and, if deemed appropriate, a revised fluence projection is prepared and the effects of the revised fluence analysis on neutron embrittlement calculations will be evaluated. If necessary an active surveillance program will be reinstituted for Hope Creek. The employment of additional surveillance specimens will be coordinated through the BWRVIP Integrated Surveillance Program (ISP). Any changes to the reactor vessel exposure conditions and the potential need to re-institute a vessel surveillance program will be discussed with the NRC staff prior to changing the plant's licensing basis.	A.2.1.21	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.21 August 18, 2009

APPENDIX A: HCGS LICENSE RENEWAL COMMITMENTS

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
22	One-Time Inspection is a new program and will be used for the following: 1. To confirm the effectiveness of the Water Chemistry program to manage the loss of material, cracking, and the reduction of heat transfer aging effects for aluminum, copper alloy, ductile cast iron, gray cast iron, nickel alloy, steel, stainless steel, and cast austenitic stainless steel in treated water, steam, sodium pentaborate and reactor coolant environments. 2. To confirm the effectiveness of the Fuel Oil Chemistry program to manage the loss of material aging effect for copper alloy, steel, galvanized steel and stainless steel in a fuel oil environment. 3. To confirm the effectiveness of the Lubricating Oil Analysis program to manage the loss of material and the reduction of heat transfer aging effects for copper alloy, gray cast iron, steel and stainless steel in a lubricating oil environment. 4. To confirm loss of material in carbon steel piping and fittings is insignificant in an air/gas-wetted (internal) environment. The sample plan for inspections associated with the One-Time Inspection program will be developed to ensure there are adequate inspections to address each of the material, environment, and aging effect combinations. A sample size of 20% of the population (up to a maximum of 25 inspections) will be established for each of the sample groups.	A.2.1.22	Program to be implemented prior to the period of extended operation. One-time inspections to be performed within the ten-year period prior to the period of extended operation.	LRA Section B.2.1.22 August 18, 2009 Hope Creek Letter LR-N11-0006 RAI B.2.1.22-1 January 6, 2011

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Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
23	Selective Leaching of Materials is a new program that will include one-time inspections of a representative sample of susceptible components to determine where loss of material due to selective leaching is occurring. A sample size of 20% of susceptible components will be subjected to a one-time inspection with a maximum of 25 inspections for each of the susceptible material groups. Where selective leaching is identified, further aging management activities will be implemented such that the component intended function is maintained consistent with the current licensing basis through the period of extended operation.	A.2.1.23	Program to be implemented prior to the period of extended operation. One-time inspections to be performed within the ten-year period prior to the period of extended operation.	LRA Section B.2.1.23 August 18, 2009 Hope Creek Letter LR-N10-0319 LRA Supplement August 26, 2010 Hope Creek Letter LR-N11-0006 RAI B.2.1.23-1 January 6, 2011
24	Buried Piping Inspection is an existing program that will be enhanced to include: 1. At least one (1) opportunistic or focused excavation and inspection will be performed on each of the material groupings, which include carbon steel, ductile cast iron, and gray cast iron piping and components during each ten (10) year period, beginning ten (10) years prior to entry into the period of extended operation. A second opportunistic or focused excavation and inspection on a carbon steel piping segment, which is not cathodically protected, will be performed on the Service Water System during each ten year period, beginning ten years prior to entry into the period of extended operation. A different segment will be inspected in each ten year period.	A.2.1.24	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	LRA Section B.2.1.24 August 18, 2009 Hope Creek Letter LR-N10-0323 RAI B.2.1.24 September 1, 2010 Hope Creek Letter LR-N10-0371 RAI B.2.1.24-02 October 29, 2010
25	External Surfaces Monitoring is a new program that directs visual inspections of components such as piping, piping components, ducting and other components in the scope of license renewal, exposed to an air environment, to manage aging effects.	A.2.1.25	Program to be implemented prior to the period of extended operation.	LRA Section B.2.1.25 August 18, 2009

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Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
26	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is a new program that manages the aging of the internal surfaces of piping, piping components and piping elements, tanks and ducting components.	A.2.1.26	Program to be implemented prior to the period of extended operation.	LRA Section B.2.1.26 August 18, 2009
27	Lubricating Oil Analysis	A.2.1.27	Ongoing	LRA Section B.2.1.27 August 18, 2009
28	ASME Section XI, Subsection IWE is an existing program that will be enhanced to include: 1. Install an internal moisture barrier at the junction of the drywell concrete floor and the steel drywell shell prior to the period of extended operation. 2. Require inspection of the moisture barrier for loss of sealing in accordance with IWE 2500 after it is installed. 3. Verify that the reactor cavity seal rupture drain lines are clear from blockage and that the monitoring instrumentation is functioning properly once prior to the period of extended operation, and one additional time during the first ten years of the period of extended operation. 4. Establish drainage capability from the bottom of the drywell air gap on or before June 30, 2015. The drywell air gap will be divided into four approximately equal quadrants. Drainage consists of one drain in each quadrant for a total of four drains. Each drain will be open at the bottom of the drywell air gap and be capable of draining water from the air gap. Verify that drains at the bottom of the drywell air gap are clear from blockage once prior to the period of extended operation, and one additional time during the first ten years of the period of extended operation. 5. Investigate the source of any leakage detected by the reactor cavity seal rupture drain line instrumentation and assess its impact on the	A.2.1.28	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	LRA Section B.2.1.28 August 18, 2009 Hope Creek Letter LR-N10-0190 RAI B.2.1.28-01 June 14, 2010 Hope Creek Letter LR-N10-0291 RAI B.2.1.28-01 August 9, 2010 Hope Creek Letter LR-N11-0016 RAI B.2.1.28-03 January 19, 2011 Hope Creek Letter LR-N11-0164 DRAI B.2.1.28-4 May 19, 2011

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	drywell shell. 6. After drainage has been established from the bottom of the air gap from all four drains, monitor the drains at the bottom of the drywell air gap daily for leakage in the event leakage is detected by the reactor cavity seal rupture drain line instrumentation. 7. Monitor penetration sleeve J13 daily for water leakage when the reactor cavity is flooded up. In addition, perform a walkdown of the torus room to detect any leakage from other drywell penetrations. These actions shall continue until corrective actions are taken to prevent leakage through J13 or through the four air gap drains. 8. Until drainage is established from all four drains, when the reactor cavity is flooded up, perform boroscope examination of the bottom of the drywell air gap through penetrations located at elevation 93' in four quadrants, 90 degrees apart. The personnel performing the boroscope examination shall be certified as VT-1 inspectors in accordance ASME Section XI, Subsection IWA-2300, requirements. The examiners will look for signs of water accumulation and drywell shell corrosion. Adverse conditions will be documented and addressed in the corrective action program. After drainage has been established from the bottom of the air gap from all four drains, monitor the lower drywell air gap drains daily for water leakage when the reactor cavity is flooded up. 9. Until drainage is established from all four drains, perform UT thickness measurements each refuel outage from inside the drywell in the area of the drywell shell below the J13 penetration sleeve area to determine if there is a significant corrosion rate occurring in this area due to periodic exposure to reactor cavity leakage. In addition, UT measurements shall be perfomed each refuel outage around the full 360 degree circumference of the drywell between elevations 86'-11" and 88'-0" (underside of the torus down comer vent piping penetrations). Inspection and acceptance criteria will be in accordance with IWE-2000 and IWE-3000 respectively. The results of the UT measurements shall be used to establish a corrosion rate and demonstrate that the effects of aging will be adequately			

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	managed such that the drywell can perform its intended function until April 11, 2046. Evidence of drywell shell degradation will be documented and addressed in the corrective action program. After drainage has been established from the bottom of the air gap from all four drains, UT thickness measurements will be taken each of the next three refueling outages at the same locations as those previously examined as described above. These UT thickness measurements will be compared to the results of the previous UT inspections and, if corrosion is ongoing, a corrosion rate will be determined for the drywell shell. In the event a significant corrosion rate is detected, the condition will be entered in the corrective action process for evaluation and extent of condition determination. 10. The cause of the reactor cavity water leakage will be investigated and repaired, if practical, before PEO. If repairs cannot be made prior to the PEO, the program will be enhanced to incorporate the following aging management activities, as recommended in the Final Interim Staff Guidance LR-ISG-2006-01. a. Identify drywell surfaces requiring examination and implement augmented inspections for the period of extended operation in accordance with IWE-1240, as identified in Table IWE-2500-1, Examination Category E-C. b. Demonstrate through the use of augmented inspections that corrosion is not occurring or that corrosion is progressing so slowly that the age-related degradation will not jeopardize the intended function of the drywell shell through the period of extended operation. c. Develop a corrosion rate that can be inferred from past UT examinations. If degradation has occurred, evaluate the drywell shell using the developed corrosion rate to demonstrate that the drywell shell will have sufficient wall thickness to perform its intended function through the period of extended operation.			
29	ASME Section XI, Subsection IWF	A.2.1.29	Ongoing	LRA Section B.2.1.29 August 18, 2009

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Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
30	10 CFR Part 50, Appendix J	A.2.1.30	Ongoing	LRA Section B.2.1.30 August 18, 2009
31	Masonry Wall is an existing program that will be enhanced to include: 1. Additional buildings and masonry walls as described in A.2.1.31. 2. Add an Examination Checklist for masonry wall inspection requirements. 3. Specify an inspection frequency of not greater than 5 years for masonry walls.	A.2.1.31	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.31 August 18, 2009
32	Structures Monitoring is an existing program that will be enhanced to include: 1. Additional structures and components as described in A.2.1.32 2. Concrete structures will be observed for a reduction in equipment anchor capacity due to local concrete degradation. This will be accomplished by visual inspection of concrete surfaces around anchors for cracking, and spalling. 3. Clarify inspection criteria for loss of material due to corrosion and pitting of additional steel components, such as embedments, panels and enclosures, doors, siding, metal deck, and anchors. 4. Perform a one-time inspection of the external stainless steel surfaces of the expansion bellows at Condensate Storage Tank Dike for loss of material due to corrosion, within the ten-year period prior to the period of extended operation. 5. Require inspection of penetration seals, structural seals and elastomers for degradations that will lead to a loss of sealing by visual inspection of the seal for hardening, shrinkage and loss of strength. 6. Require monitoring of vibration isolators, associated with component supports other than those covered by ASME XI, Subsection IWF. 7. Add an Examination Checklist for masonry wall inspection requirements. 8. Parameters monitored for wooden components will be enhanced to include: Change in Material Properties, Loss of Material due to Insect Damage and Moisture Damage.	A.2.1.32	Program to be enhanced prior to the period of extended operation. One-time inspection to be performed within the ten-year period prior to the period of extended operation.	LRA Section B.2.1.32 August 18, 2009

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Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
	9. Specify an inspection frequency of not greater than 5 years for structures including submerged portions of the Service Water Intake Structure. 10. Require individuals responsible for inspections and assessments for structures to have a B.S. Engineering degree and/or Professional Engineer license, and a minimum of four years experience working on building structures. 11. Perform periodic sampling, testing, and analysis of ground water chemistry for pH, chlorides, and sulfates on a frequency of 5 years. 12. Require supplemental inspections of the in scope structures within 30 days following extreme environmental or natural phenomena (large floods, significant earthquakes, hurricanes, and tornadoes). 13. Perform a chemical analysis of ground or surface water in-leakage when there is significant in-leakage or there is reason to believe that the in-leakage may be damaging concrete elements or reinforcing steel. 14. Implementing procedures will be enhanced to include additional acceptance criteria details specified in ACI 349.3R-96.			

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Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
33	RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" is an existing program that will be enhanced to include: 1. Shoreline Protection and Dike structures will be added to the program. 2. Parameters monitored for wooden components will be enhanced to include change in material properties and loss of material due to insect damage and moisture damage. 3. The inspection requirement for submerged concrete structural components will be enhanced to require that inspections be performed by dewatering a pump bay or by a diver if the pump bay is not dewatered. 4. Specify an inspection frequency of not greater than 5 years for structures including submerged portions of the Service Water Intake Structure. 5. Require supplemental inspections of the in scope structures within 30 days following extreme environmental or natural phenomena (large floods, significant earthquakes, hurricanes, and tornadoes).	A.2.1.33	Program to be enhanced prior to the period of extended operation.	LRA Section B.2.1.33 August 18, 2009
34	Protective Coating Monitoring and Maintenance Program	A.2.1.34	Ongoing	LRA Section B.2.1.34 August 18, 2009
35	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program and will be used to manage aging of non-EQ cables and connections during the period of extended operation.	A.2.1.35	Program and initial inspections to be implemented prior to the period of extended operation.	LRA Section B.2.1.35 August 18, 2009

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Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
36	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits is a new program that will be implemented to manage the aging of the cable and connection insulation of the in scope portions of the Leak Detection and Radiation Monitoring System, and the Neutron Monitoring System.	A.2.1.36	Program and initial assessment of testing and calibration results to be implemented prior to the period of extended operation.	LRA Section B.2.1.36 August 18, 2009

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Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
37	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to manage the aging effects and mechanisms of non-EQ, in scope inaccessible power cables (480V, 4,160V, 13,800V). The cable test frequency will be established based on test results and industry operating experience. The maximum time between tests will be no longer than 6 years. Manholes and cable vaults associated with the cables included in this aging management program will be inspected for water collection (with water removal as necessary) with the objective of minimizing the exposure of power cables to significant moisture. Prior to the period of extended operation, the frequency of inspections for accumulated water will be established based on inspection results to minimize the exposure of power cables to significant moisture. The maximum time between inspections will be no longer than one year. The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be enhanced as follows: 1. Add low voltage power cables (480 volts or greater) to the scope of the program. 2. Change cable testing maximum frequency from 10 years to 6 years. Change cable vault and manhole inspection maximum frequency from 2 years to 1 year.	A.2.1.37	Enhanced program and initial cable tests and manhole inspections to be implemented prior to the period of extended operation. Test and inspection schedule identified in commitment.	LRA Section B.2.1.37 August 18, 2009 Hope Creek Letter LR-N10-0190 RAI B.2.1.37-01 June 14, 2010 Hope Creek Letter LR-N10-0190 RAI B.2.1.37-02 June 14, 2010 Hope Creek Letter LR-N10-0325 LRA Supplement September 7, 2010 Hope Creek Letter LR-N10-0360 LRA Supplement September 30, 2010
38	Metal Enclosed Bus is a new program that will manage the aging of in-scope metal enclosed busses.	A.2.1.38	Program and initial inspections to be implemented prior to the period of extended operation.	LRA Section B.2.1.38 August 18, 2009

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Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
39	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to confirm the absence of an aging effect with respect to electrical cable connection stressors. A representative sample of non-EQ electrical cable connections will be selected, for one-time testing considering application (medium and low voltage), circuit loading (high loading) and location, with respect to connection stressors.	A.2.1.39	Program and one-time testing to be implemented prior to the period of extended operation.	LRA Section B.2.1.39 August 18, 2009
40	High Voltage Insulators is a new program that manages the degradation of insulator quality due to the presence of salt deposits or surface contamination.	A.2.2.1	Program to be implemented prior to the period of extended operation.	LRA Section B.2.2.1 August 18, 2009
41	Periodic Inspection is a new program that manages the aging of piping, piping components, piping elements, ducting components, tanks and heat exchanger components.	A.2.2.2	Program to be implemented prior to the period of extended operation.	LRA Section B.2.2.2 August 18, 2009
42	Aboveground Non-Steel Tanks is a new program that will manage loss of material of outdoor non-steel tanks. The Aboveground Non-Steel Tanks program will include a UT wall thickness inspection of the bottom of the only tank in the program, which is the stainless steel condensate storage tank. The UT measurements will be taken to ensure that significant degradation is not occurring and that the component intended function will be maintained during the extended period of operation.	A.2.2.3	Program to be implemented prior to the period of extended operation. Tank bottom UT inspections will also be performed prior to the period of extended operation.	LRA Section B.2.2.3 August 18, 2009

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Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
43	Buried Non-Steel Piping Inspection is an existing program that will be enhanced to include: 1. At least one (1) opportunistic or focused excavation and inspection will be performed on buried reinforced concrete piping and components during each ten (10) year period, beginning ten (10) years prior to entry into the period of extended operation. 2. At least one (1) opportunistic or focused excavation and inspection will be performed on Condensate Storage and Transfer System buried stainless steel piping and components, which contain fluid that exceed EPA drinking water limits, during each ten (10) year period, beginning ten (10) years prior to entry into the period of extended operation. 3. Guidance for inspection of concrete aging effects.	A.2.2.4	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	LRA Section B.2.2.4 August 18, 2009 Hope Creek Letter LR-N10-0323 RAI B.2.1.24 September 1, 2010 Hope Creek Letter LR-N10-0371 RAI B.2.1.24-02 October 29, 2010
44	Boral Monitoring Program is an existing program that will be enhanced to include: 1. Inspection, testing and evaluation of one coupon from the Hope Creek spent fuel pool prior to the period of extended operation and one coupon within the first 10 years after entering the period of extended operation. Testing will include dimensional and neutron attenuation measurements with an acceptance criteria of no more than a 10% increase in thickness and no more than a 5% decrease in B-10 areal density.	A.2.2.5	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment	LRA Section B.2.2.5 August 18, 2009 Hope Creek Letter LR-N10-0154 RAI 2.2.5-1 May 11, 2010

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Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
45	Small-Bore Class 1 Piping is a new program that will manage the aging effects of cracking in small-bore (greater than or equal to NPS 1 and less than NPS 4) Class 1 piping through the use of a combination of volumetric examinations and visual inspections.	A.2.2.6	Program to be implemented prior to the period of extended operation, with the supplemental inspections performed within the six year period prior to the period of extended operation.	LRA Section B.2.2.6 August 18, 2009 Hope Creek Letter LR-N10-0415 RAI B.2.2.6-01 December 15, 2010
46	Metal Fatigue of the Reactor Coolant Pressure Boundary is an existing program that will be enhanced to include: 1. Adding transients beyond those defined in the Technical Specifications and the UFSAR, and expanding the fatigue monitoring program to encompass other components identified to have fatigue as an analyzed aging effect, which require monitoring. 2. Using a software program to automatically count transients and calculate cumulative usage on select components. At this time only cycle–based fatigue monitoring will be used. If stress–based fatigue monitoring is used in the future, it will consider the six stress terms in accordance with the methodology from ASME Section III, Subsection NB, Subarticle NB-3200. 3. Addressing the effects of the reactor coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components for the plant identified in NUREG/CR-6260. 4. Requiring a review of additional reactor coolant pressure boundary locations if the usage factor for one of the environmental fatigue sample locations approaches its design limit.	A.3.1.1	Program to be enhanced prior to the period of extended operation.	LRA Section B.3.1.1 August 18, 2009 Hope Creek Letter LR-N10-0356 RAI 4.3-01 September 20, 2010

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Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
47	Environmental Qualification of Electric Components (EQ)	A.3.1.2	Ongoing	LRA Section B.3.1.2 August 18, 2009
48	New P-T Curves Revised Pressure-Temperature (P-T) limits will be submitted to the NRC when necessary to comply with 10 CFR 50 Appendix G.	A.4.2.3	Ongoing	LRA Section 4.2.3 August 18, 2009
49	RPV Circumferential Weld Examination Relief PSEG will request relief from the requirement to perform volumetric examinations of the Reactor Pressure Vessel Circumferential Welds, in accordance with 10 CFR 50.55(a)	A.4.2.4	Prior to the period of extended operation.	LRA Section 4.2.4 August 18, 2009
50	Operating Experience Review PSEG will perform an evaluation of operating experience at extended power uprate (EPU) levels prior to the period of extended operation to ensure that operating experience at EPU levels is properly addressed by the aging management programs. The evaluation will include Hope Creek and other BWR plants operating at EPU levels.	All programs	Prior to the period of extended operation.	NUREG-1800 Section 3.0.2
51	Reactor Internals Components – Core Plate Rim Hold-Down Bolts PSEG will perform one of the following: 1. Install core plate wedges, or 2. Perform an analysis that demonstrates the component function is maintained.	A.4.2.7	Prior to the period of extended operation.	LRA Section 4.2.7 and Appendix C August 18, 2009

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Item Number	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
52	Jet Pump Slip Joint Clamp Bolt PSEG will replace the slip joint clamp or perform an analysis that demonstrates the function of the component is maintained.	A.4.7.3	Two years before reaching the bounding value of 35.4 EFPY, perform the analysis, or replace the slip joint clamp at a refueling outage prior to reaching the bounding value of 35.4 EFPY.	LRA Section 4.7.3 August 18, 2009 Hope Creek Letter LR-N10-0344 September 9, 2010
53	Metal Fatigue of Reactor Coolant Pressure Boundary Environmental fatigue calculations for the Hope Creek Alloy 600 locations will use the data and the methodology that is described in NUREG/CR-6909 or later revisions/reports for Ni-Cr-Fe alloys in the determination of the F_{en} factor and fatigue usage.	A.3.1.1 A.4.3.5	Upon calculation revision/update	Hope Creek Letter LR-N10-0344; RAI 4.3-07 September 9, 2010
54	Metal Fatigue of Reactor Coolant Pressure Boundary PSEG will perform a review of design basis ASME Code Class 1 component fatigue evaluations to determine whether the NUREG/CR-6260 based components that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting components for the Hope Creek plant configuration. If more limiting components are identified, the most limiting component will be evaluated for the effects of the reactor coolant environment on fatigue usage. If any of the limiting locations consist of nickel alloy, NUREG/CR-6909 methodology for nickel alloy will be used in the evaluation.	A.3.1.1 A.4.3.5	Prior to the period of extended operation.	Hope Creek Letter LR-N10-0440; CI 4.3.5.2-1 January 6, 2011

APPENDIX B

CHRONOLOGY

This appendix contains a chronological listing of the routine correspondence between the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) and PSEG Nuclear, LLC (PSEG or the applicant), and other correspondence regarding the staff's reviews of the Hope Creek Generating Station (HCGS), Docket Number 50-354, license renewal application (LRA).

August 18, 2009	Hope Creek Generating Station, License Renewal Application, Volume 1 of 3. (Accession No. ML092430373)
August 18, 2009	Hope Creek Generating Station, License Renewal Application, Volume 2 of 3. (Accession No. ML092430374)
August 18, 2009	Letter from C.J. Fricker, PSEG Nuclear, LLC: Hope Creek Generating Station Transmittal Letter, License Renewal Application. (Accession No. ML092430375)
August 18, 2009	Hope Creek Generating Station, License Renewal Application, Volume 3 Through Appendix A. (Accession No. ML092430384)
August 18, 2009	Hope Creek Generating Station, License Renewal Application, Volume 3, Appendix B. (Accession No. ML092430386)
August 18, 2009	Hope Creek Generating Station, License Renewal Application, Volume 3, Appendix C. (Accession No. ML092430387)
August 18, 2009	Hope Creek Generating Station, License Renewal Application, Volume 3, Appendix D. (Accession No. ML092430388)
August 18, 2009	Hope Creek Generating Station, License Renewal Application, Volume 3, Appendix E. (Acccession No. ML092430389)
August 18, 2009	Hope Creek Generating Station, License Renewal Application, Volume 3, Appendix F. (Accession No. ML092430390)
August 18, 2009	Hope Creek Generating Station, License Renewal Application, Volume 3 of 3. (Accession No. ML092430484)
August 27, 2009	Logistics Trip Report to Delaware Emergency Management Agency Regarding Salem-Hope Creek License Renewal. (Accession No. ML092360621)
August 31,2009	Federal Register Notice: Notice of Receipt and Availability of Application for Renewal of Hope Creek Generating Station. (Accession No. ML092290801)
August 31, 2009	Letter to T. Joyce, PSEG Nuclear, LLC: Receipt and Availability of the License Renewal Application for the Hope Creek Generating Station. (Accession No. ML092290793)

September 1, 2009	Press Release-09-144: NRC Announces Availability of License Renewal Applications for Salem and Hope Creek Nuclear Power Plants. (Accession No. ML092440653)
September 3, 2009	Comment of W.R. Dunn on the Salem Nuclear Generating Station and Hope Creek Generating Station License Renewal Applications. (Accession No. ML092460442)
September 3, 2009	Comment (7) of William R. Dunn, Supporting the Salem Nuclear Generating Station and Hope Creek Generating Station License Renewal Applications. (Accession No. ML102280561)
September 7, 2009	Comment of S.J. Goodman on the Salem Nuclear Generating Station and Hope Creek Generating Station License Renewal Applications. (Accession No. ML092660174)
September 7, 2009	Comment (2) of Sidney J. Goodman Opposing on License Renewal for the Salem Nuclear Generating Station and Hope Creek Generating Station (Accession No. ML102280556)
September 8, 2009	Comment of F. Berryhill on the Salem Nuclear Generating Station and Hope Creek Generating Station License Renewal Applications. (Accession No. ML092650382)
September 23, 2009	Comment of R. Panella on the Salem Nuclear Generating Station and Hope Creek Generating Station License Renewal Applications. (Accession No. ML092660447)
October 8, 2009	Letter from C.M. Dolphin, State of New Jersey, Department of Environmental Protection: New Jersey Coastal Zone Management Consultation Response for Hope Creek License Renewal. (Accession No. ML101970076)
October 15, 2009	Letter to T. Joyce, PSEG Nuclear, LLC. Determination of Acceptability and Sufficiency for Docketing, Proposed Review Schedule, and Opportunity for a Hearing Regarding the Application from PSEG Nuclear, LLC, for Renewal of the Operating License for Hope Creek Generating Station. (Accession No. ML092780127)
October 15, 2009	Federal Register: Notice of Federal Acceptability for Docketing of the Application and Notice of Opportunity for Hearing Regarding Renewal of Facility Operating License No. NPF-57 for an Additional 20-Year Period, PSEG Nuclear, LLC, Hope Creek Nuclear Generating Station. (Accession No. ML092780147)
October 15, 2009	Letter to T. Joyce, PSEG Nuclear, LLC: Notice of Intent to Prepare an Environmental Impact Statement and Conduct the Scoping Process for License Renewal for the Salem Nuclear Generating Station, Units 1 and 2, and the Hope Creek Generating Station. (Accession No. ML092740412)

October 23, 2009	Notice of Meeting on November 5, 2009, to Discuss License Renewal Process and Environmental Scoping for Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station, License Renewal Application Review. (Accession No. ML092870635)
October 24, 2009	Comment of D.O. Rickards on the Salem Nuclear Generating Station and Hope Creek Generating Station License Renewal Applications. (Accession No. ML100570265)
November 3, 2009	Comment (5) of Ellen B. Pompper, on Behalf of Self, Supporting PSEG Nuclear's License Renewal for Salem Nuclear Generating Station and Hope Creek Generating Station. (Accession No. ML102280559)
November 5, 2009	Transcript of the Salem and Hope Creek License Renewal Public Meeting, November 5, 2009, Pages 1–79. (Accession No. ML093240195)
November 5, 2009	Transcript of the Salem and Hope Creek License Renewal Process, Public Meeting: Evening Session November 5, 2009, Pages 1–63. (Accession No. ML100471177)
November 12, 2009	Letter to J. Douglas, Delaware Tribe of Indians: Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Nuclear Generating Station, Unit 1, License Renewal Applications. (Accession No. ML093090124)
November 24, 2009	Letter to J. Cutler, Deputy State Historic Preservation Officer (SHPO), Pennsylvania Bureau for Historic Preservation; J.R. Little, Director and SHPO, Maryland Historical Trust; D. Saunders, Deputy SHPO, New Jersey Historic Preservation Office; and T.A. Slavin, SHPO, Delaware Division of Historical and Cultural Affairs: Salem Nuclear Generating Station and Hope Creek Generation Station License Renewal Applications Review. (Accession No. ML093160444)
December 22, 2009	Letter from T.A. Slavin, State of Delaware Historical and Cultural Affairs: Delaware SHPO Finding of No Adverse Impact Consultation Response for the Salem and Hope Creek License Renewal. (Accession No. ML101970071)
December 23, 2009	Letter to A.E. Scherer, U.S. Fish and Wildlife Service: Request for List of Protected Species and Water Usage Impacts Within the Area Under Evaluation for the Salem and Hope Creek Nuclear Generating Stations License Renewal Application Review. (Accession No. ML093350019)
December 23, 2009	Letter to P.A. Kurkul, National Marine Fisheries Service: Request for List of Protected Species Within the Area Under Evaluation for the Salem and Hope Creek Nuclear Generating Stations License Renewal Application Review. (Accession No. ML093500057)
February 11, 2010	Letter from M.A. Colligan, National Marine Fisheries Service: NMFS Consultation Response for the Salem and Hope Creek License Renewal Project. (Accession No. ML101970073)

February 23, 2010	Letter from S.W. Gorski, National Marine Fisheries Service: NMFS Habitat Conservation Division Consultation Response for the Salem and Hope Creek License Renewal Project. (Accession No. ML101970072)
March 22, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Section 2.3.2, Containment for the Hope Creek Generating Station. (Accession No. ML100630287)
March 29, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Corrections to the Hope Creek Generating Station License Renewal Application. (Accession No. ML100910160)
March 31, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Section 2.4, Scoping and Screening Results: Structures (TAC No. ME1832). (Accession No. ML100750328)
April 6, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Project Manager Change for the License Renewal of Hope Creek Generating Station (TAC No. ME1832). (Accession No. ML100850462)
April 6, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Corrections to the Hope Creek Generating Station License Renewal Application Environmental Report. (Accession No. ML100980029)
April 6, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated March 22, 2010, Related to Section 2.3 of the License Renewal Application. (Accession No. ML100980043)
April 6, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated March 22, 2010, Related to Section 2.3.3.10 of the License Renewal Application. (Accession No. ML100990236)
April 14, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Section 2.2.5, Boral Monitoring Program (TAC No. ME1832). (Accession No. ML100970350)
April 16, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the License Renewal Application for Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station. (Accession No. ML100910367)
April 22, 2010	Letter from P.J. Davidson, PSEG Nuclear, LLC: Response to NRC Request for Additional Information dated March 31, 2010, Related to Section 2.4 of the License Renewal Application. (Accession No. ML101160398)

April 27, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Section 2.1, Scoping and Screening Methodology (TAC No. ME1832). (Accession No. ML101020511)
April 29, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application. (Accession No. ML101440272)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Post Audit Information, Question # GEN-4. (Accession No. ML101440273)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Cultural Resources. (Accession No. ML101440276)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology. (Accession No. ML101440278)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology, Chapter 7: Marsh Restoration Project, Fish Assemblage Structure. (Accession No. ML101440279)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology, Question # ECO-7. (Accession No. ML101440280)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology, Appendix E. (Accession No. ML101440281)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology, Appendix E, Attachment E-2. (Accession No. ML101440283)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology, Appendix F. (Accession No. ML101440285)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Ecology, Appendix F, Attachment 5. (Accession No. ML101440286)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Land Use and Socioeconomics. (Accession No. ML101440287)

April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Threatened and Endangered Species. (Accession No. ML101440288)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Water/Groundwater. (Accession No. ML101440289)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Waste. (Accession No. ML101440292)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Air. (Accession No. ML101440293)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Alternatives. (Accession No. ML101440294)
April 29, 2010	Response to NRC Request for Additional Information, dated April 16, 2010, Related to the Environmental Review, License Renewal Application, Fact Sheet for a Draft NJPDES Permit. (Accession No. ML101440297)
May 11, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated April 15, 2010, Related to Scoping and Screening Results, Section 2.3 of the License Renewal Application. (Accession No. ML101340110)
May 11, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated April 14, 2010, Related to Section B.2.2.5 of the License Renewal Application. (Accession No. ML101340117)
May 14, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application Identified During the Audit (TAC No. ME1832). (Accession No. ML101060155)
May 20, 2010	Division of License Renewal's Transition from Paper Distribution to Electronic Distribution of Outgoing Correspondence. (Accession No. ML101310138)
May 24, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated April 27, 2010, Related to Section 2.1, Scoping and Screening Methodology, of the License Renewal Application. (Accession No. ML101480130)
May 28, 2010	Summary of Telephone Conference Call Held on March 4, 2010, Between the NRC and PSEG Nuclear, LLC Concerning Draft REI's Pertaining to the Hope Creek Generating Station, License Renewal Application. (Accession No. ML101340462)

June 1, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Section 3.3.2 (TAC No. ME1832). (Accession No. ML101380316)
June 1, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Sections 4.6 and 4.7 (TAC No. ME1832). (Accession No. ML101380620)
June 1, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated April 20, 2010, Related to the Severe Accident Mitigation Alternatives Review Associated with the License Renewal Application. (Accession No. ML101550149)
June 3, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application (TAC No. ME1832). (Accession No. ML101450179)
June 7, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application for Section 3.5 (TAC No. ME1832). (Accession No. ML101380149)
June 14, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application (TAC No. ME1832). (Accession No. ML101370761)
June 14, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated May 14, 2010, Related to the Aging Management Program Audit Associated with the License Renewal Application. (Accession No. ML101680503)
June 22, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Fire Protection (TAC No. ME1832). (Accession No. ML101610448)
June 24, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information Related to Sections 4.6 and 4.7 of the License Renewal Application. (Accession No. ML101810072)
June 24, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: 10 CFR 54.21(b) Review to Identify any Current Licensing Basis (CLB) Changes Made Since the Submittal of the License Renewal Application. (Accession No. ML101810073)
June 24, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 1, 2010, Related to Section 3.3.2 of the License Renewal Application. (Accession No. ML101820089)

June 25, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Section 4.3. (Accession No. ML101590675)
June 25, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Open-Cycle Cooling Water System Program and Structures (TAC No. ME1832). (Accession No. ML101660150)
June 29, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application for Fiberglass Doors (TAC No. ME1832). (Accession No. ML101750024)
June 29, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 7, 2010, Related to Section 3.5 of the License Renewal Application. (Accession No. ML101820580)
June 29, 2010	Letter from R. Popowski, U.S. Fish and Wildlife Service: Fish and Wildlife Consultation Response for the Salem and Hope Creek License Renewal Project. (Accession No. ML101970077)
June 30, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Metal Fatigue of Reactor Coolant Pressure Boundary Program (TAC No. ME1832). (Accession No. ML101580481)
June 30, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 3, 2010, Related to Sections 3.2.2, 3.3.2, and B.2.2.2 of the License Renewal Application. (Accession No. ML101830410)
July 6, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 9, 2010, Related to Sections 3.1.2 and 3.3.2 of the License Renewal Application. (Accession No. ML101900006)
July 12, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Compressed Air Monitoring (TAC No. ME1832). (Accession No. ML101810239)
July 12, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 14, 2010, Related to Section 3 of the License Renewal Application. (Accession No. ML101950358)
July 20, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 25, 2010, Related to Open-Cycle Cooling Water System Program and Structures of the License Renewal Application. (Accession No. ML102040513)

July 22, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 25, 2010, Related to Section 4.3 of the License Renewal Application. (Accession No. ML102070550)
July 22, 2010	Letter from P. J.Davidson, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 22, 2010, Related to Fire Protection License Renewal Application. (Accession No. ML102030259)
July 26, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated June 30, 2010, Related to Metal Fatigue Reactor Coolant Pressure Boundary Program; Fiberglass Doors; and Compressed Air Monitoring of the License Renewal Application. (Accession No. ML102110044)
August 3, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Bolting and Flow Element (TAC No. ME1832). (Accession No. ML102000293)
August 6, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Buried Piping Inspection Program (TAC No. ME1832). (Accession No. ML101540054)
August 9, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Supplement to PSEG Response to Requests for Additional Information (RAIs) B.2.1.28-01, B.2.1.37-01, and B.2.1.37-02 Associated with the Hope Creek Generating Station License Renewal Application. (Accession No. ML102240095)
August 13, 2010	Summary of Telephone Conference Call Held on July 29, 2010, Between the U.S. NRC and PSEG Nuclear LLC, Concerning Follow-Up Questions Pertaining to the Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station License Renewal Environmental Review. (Accession No. ML102220012)
August 18, 2010	Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application, Primary Containment Valve Material. (Accession No. ML102030398)
August 18, 2010	Summary of Telephone Conference Call Held on August 4, 2010, Between the U.S. NRC and PSEG Nuclear, LLC, Concerning Draft Requests for Additional Information Pertaining to the Hope Creek Generating Station License Renewal Application. (Accession No. ML102220476)
August 18, 2010	Letter from C.T. Neely, PSEG Nuclear, LLC: Supplement to RAI Responses Submitted in PSEG Letter LR-N10-0181, dated June 1, 2010, Related to the Severe Accident Mitigation Alternatives Review. (Accession No. ML102320212)
August 19, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Scoping and Screening Audit Summary Regarding the Hope Creek Generating Station License Renewal Application. (Accession No. ML102100544)

August 26, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Supplement to Hope Creek License Renewal Application Related to the Selective Leaching Program. (Accession No. ML 102330677)
August 26, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated August 3, 2010, Related to Bolting and Flow Element, and Update to PSEG July 6, 2010, Response to NRC Request for Additional Information Associated with the RPV Leak Detection Line, License Renewal Application. (Accession No. ML102330678)
September 1, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Updated Response to NRC Request for Additional Information 3.5.2.1.4 and Responses to NRC Request for Additioinal Information 3.2.1.20-01 Associated with Renewal Application. (Accession No. ML102500118)
September 1, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Response to NRC Request for Additional Information, dated August 6, 2010, Related to the Buried Piping Inspection Program Associated with the License Renewal Application. (Accession No. ML102500101)
September 2, 2010	Letter to C. Fricker, PSEG Nuclear, LLC: Revised Review Schedule Regarding the Application from PSEG Nuclear, LLC for Renewal of the Operating Licenses for Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station (TAC Nos. ME1835, ME1833, and ME1831). (Accession No. ML102360221)
September 2, 2010	Summary of Telephone Conference Call Held on June 21, 2010, Between the NRC and PSEG Nuclear, LLC Concerning Responses to Requests for Additional Information Pertaining to the Hope Creek Generating Station, License Renewal Application. (Accession No. ML102320179)
September 3, 2010	Letter to T. Joyce, PSEG Nuclear, LLC: Regarding Audit Report of the Hope Creek Generating Station License Renewal Application. (Accession No. ML101660452)
September 3, 2010	Summary of Telephone Conference Call Held on August 16, 2010, Between the NRC and PSEG Nuclear, LLC Concerning Draft Request for Additional Information Pertaining to the Hope Creek Generating Station, License Renewal Application. (Accession No. ML102320178)
September 7, 2010	Letter from R.C. Braun, PSEG Nuclear LLC: Supplement to License Renewal Application to include Low Voltage Power Cables in the Scope of the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (E-3) Program. (Accession No. ML102530452)
September 20, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Hope Creek Revised RAI 4.3-01 Response Associated with the License Renewal Application. (Accession No. ML102660024)
September 29, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Environmental Project Manager Change for the License Renewal of Hope Creek Generating Station (TAC No. ME1831). (Accession No. ML102600324)

September 29, 2010	Federal Register: Notice Regarding the ACRS Subcommittee Meeting on Plant License Renewal (Hope Creek), November 3, 2010. (Accession No. ML102720723)
September 30, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Safety Evaluation Report Related to the License Renewal of Hope Creek Generating Station. (Accession No. ML102660148)
September 30, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: Hope Creek - Supplement Response to RAIs B.2.1.37-01 and B.2.1.37-02 to License Renewal Application to Revise the Maximum Cable Testing and Cable Vault Inspection Frequencies and Clarify Related Information in Inaccessible Medium Voltage Cables. (Accession No. ML102790058)
September 30, 2010	Memoranda from B.M. Pham to E.M. Hackett: Advisory Committee on Reactor Safeguards Review of the Hope Creek Generating Station License Renewal Application - Safety Evaluation Report with Open Items. (Accession No. ML102710067)
October 1, 2010	Letter from R.J. Conte to T.P. Joyce, PSEG Nuclear, LLC: IR 05000272, 05000311, 05000354-10-010; June 7-10, 21-24, August 9 -12, 26, 2010; Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station; License Renewal Inspection Report of the Scoping of Non-Safety Systems and the Proposed Aging Management. (Accession No. ML102740350)
October 12, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application for Buried Piping (TAC No. ME1832). (Accession No. ML102780422)
October 14, 2010	Letter from R.J. Conte to T.P. Joyce, PSEG Nuclear, LLC: IR 05000272-10-006, 05000311-10-006, 05000354-10-006 on 6/7/10 - 06/10/10, 06/21/10 - 06/24/10 and 8/9/10 - 08/12/10 for Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station; License Renewal Inspection Report - Errata. (Accession No. ML102871030)
October 21, 2010	Letter to C. Fricker, PSEG Nuclear, LLC: Issuance of the Environmental Scoping Summary Report for the Staff's Review of the License Renewal Application for Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station. (Accession No. ML102350315)
October 21, 2010	Letter from B.M. Pham to U.S. Environmental Protection Agency, Office of Federal Activities: Notice of Availability of the Draft Plant-Specific Supplement 45 to the Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding the Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2. (Accession No. ML102930322)
October 21, 2010	Federal Register: Notice of Availability of the Draft Supplement 45 to the Generic Environmental Impact Statement for the License Renewal of Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station. (Accession No. ML102780678)

October 21, 2010	Federal Register: Notice of Availability of Draft Plant-Specific Supplement 45 to the Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding the Salem Nuclear Generating Station, Units 1 and 2, and the Hope Creek Generating Station. (Accession No. ML102790646)
October 28, 2010	Notice of Meeting on November 17, 2010, to Discuss the Draft Supplemental Environmental Impact Statement for the License Renewal of Hope Creek Generating Station and Salem Nuclear Generating Station Units 1 and 2. (Accession No. ML102950006)
October 29, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Hope Creek - Response to NRC Request for Additional Information, dated October 12, 2010, Related to Buried Piping Inspection Program License Renewal Application. (Accession No. ML103070480)
October 31, 2010	NUREG-1437, Supplement 45, Volume 1, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2," Main Report (Draft for Comment). (Accession No. ML102940169)
October 31, 2010	NUREG-1437, Supplement 45, Volume 2, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2," Appendices (Draft for Comment). (Accession No. ML102940267)
November 2, 2010	Summary of Telephone Conference Call Held on September 9, 2010, Between NRC and PSEG Concerning an LRA Supplement Pertaining to the Hope Creek Generating Station, License Renewal Application. (Accession No. ML102590383)
November 3, 2010	Letter to M.A. Colligan, U.S. Department of Commerce, National Marine Fisheries Service: Notice of Availability of the Draft Plant-Specific Supplement 45 to the Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2. (Accession No. ML103000444)
November 3, 2010	Letter to S.W. Gorski, U.S. Department of Commerce, National Marine Fisheries Service: Notice of Availability of the Draft Plant-Specific Supplement 45 to the Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2. (Accession No. ML103000462)
November 5, 2010	Letter to D. Saunders, T.A. Slavin, State of New Jersey, Historic Preservation Office: Hope Creek and Salem Station License Renewal Application Review. (Accession No. ML103000463)

November 5, 2010	Letter to A.E. Scherer, U.S. Department of Interior, Fish and Wildlife Service: Notice of Availability of the Draft Plant-Specific Supplement 45 to the Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2. (Accession No. ML103020133)
November 8, 2010	Letter from B.M. Pham, to J. Douglas (similar letters sent to 18 tribes): Notice of Availability of the Draft Plant-Specific Supplement 45 to the Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding the Hope Creek Generating Station and Salem Nuclear Generating Statioin, Units 1 and 2. (Accession No. ML103050427)
November 9, 2010	Press Release-I-10-046: NRC to Seek Public Input on Nov. 17 on Draft Environmental Reports for Salem, Hope Creek Nuclear Plant License Renewal Applications. (Accession No. ML103130288)
November 15, 2010	Letter from P.J. Davison, PSEG Nuclear, LLC: PSEG Nuclear, LLC Review of the Safety Evaluation Report with Open Items Associated with the Hope Creek Generating Station License Renewal Application. (Accession No. ML103220259)
November 17, 2010	Transcript of Public Meetings Conducted to Discuss the Draft Supplemental Environmental Impact Statement Related to the Review of the Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2, License Renewal Application. (Accession No. ML103400276)
November 17, 2010	Transcript of Public Meetings Conducted to Discuss the Draft Supplemental Environmental Impact Statement Related to the Review of the Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2, License Renewal Application. (Accession No. ML103400279)
November 19, 2010	Summary of Telephone Conference Call Held on October 21, 2010, Between the NRC and PSEG Nuclear, LLC Concerning Hope Creek Generating Station, License Renewal Application, Environmentally Assisted Fatigue Analysis. (Accession No. ML103190745)
December 9, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application for Small-Bore Class 1 Piping Inspection Program (TAC No. ME4808). (Accession No. ML103210244)
December 9, 2010	Memoranda from L.T. Perkins, to B.M. Pham, NRC/NRR/DLR/RPB1: Summary of Public Meetings Conducted to Discuss the Draft Supplemental Environmental Impact Statement Related to the Review of the Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2, License Renewal Application. (Accession No. ML103280577)

December 13, 2010	Letter to T.P. Joyce, PSEG Nuclear, LLC: Request for Additional Information for the Review of the Hope Creek Generating Station License Renewal Application for One Time Inspection and Selective Leaching (TAC No. ME1832). (Accession No. ML103280574)
December 13, 2010	Letter to M.A. Colligan, U.S. Department of Commerce, National Marine Fisheries Service: Biological Assessment for License Renewal of the Hope Creek Generating Station, Unit 1, and Salem Nuclear Generating Station, Units 1 and 2. (Accession No. ML103350271)
December 15, 2010	Letter from R.C. Braun, PSEG Nuclear, LLC: Hope Creek Response to NRC Request for Additional Information, dated December 9, 2010, Related to the Small-Bore Class 1 Piping Program Associated with Hope Creek License Renewal Application. (Accession No. ML103550230)
December 16, 2010	Comment (3) of Robert K. Marshall, on Behalf of New Jersey Energy Coalition, on NRC Generic Environmental Impact Statement for License Renewal Regarding Hope Creek Generating Station and Salem Generating Station, Units 1 and 2. (Accession No. ML103560019)
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March 1, 2011	Minutes of the Meeting of the Subcommittee on Plant License Renewal Regarding Hope Creek Generating Station on November 3, 2010, in Rockville, Maryland. (Accession No. ML110600557)
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June 8, 2011	Summary of Telephone Conference Call Held on May 9, 2011, Between the U.S. Nuclear Regulatory Commission and PSEG Nuclear, LLC, Concerning Status of Hope Creek Drywell Air Gap Drains. (Accession No. ML11138A321)
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June 16, 2011	Letter to Gregory B. Jaczko, Chairman, USNRC: Report on the Safety Aspects of the License Renewal Application for the Hope Creek Generating Station. (Accession No. ML11164A049)

APPENDIX C

PRINCIPAL CONTRIBUTORS

This appendix lists the principal contributors for the development of this safety evaluation report (SER) and their areas of responsibility.

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APPENDIX D

REFERENCES

This appendix contains a listing of the references used in the preparation of the Safety Evaluation Report (SER) prepared during the review of the license renewal application (LRA) for Hope Creek Generating Station (HCGS), Docket Number 50-354.

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NRC FORM 335 (12-2010) NRCMD 3.7 **BIBLIOGRAPHIC DATA SHEET** *(See instructions on the reverse)*	U.S. NUCLEAR REGULATORY COMMISSION	1. REPORT NUMBER (Assigned by NRC, Add Vol., Supp., Rev., and Addendum Numbers, if any.) NUREG-2102

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8. PERFORMING ORGANIZATION - NAME AND ADDRESS *(If NRC, provide Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address; if contractor, provide name and mailing address.)*

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Arthur Cunanan, NRC Project Manager

11. ABSTRACT *(200 words or less)*

This safety evaluation report (SER) documents the technical review of the Hope Creek Generating Station (HCGS), license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated August 18, 2009, PSEG Nuclear, LLC (PSEG or the applicant) submitted the LRA in accordance with Title 10, Part 54, of the Code of Federal Regulations, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." PSEG requests renewal of the operating license (Facility Operating License Number NPF-57) for a period of 20 years beyond the current expiration at midnight April 11, 2026.

HCGS is located approximately 40 miles from Philadelphia, Pennsylvania, and 8 miles from Salem, New Jersey. The NRC issued the construction permit on November 4, 1974, and the operating license on July 25, 1986. The unit is a Mark I boiling-water reactor design. The licensed power output of the unit is 3,840 megawatt thermal with a gross electrical output of approximately 1,268 megawatt electric.

This SER presents the status of the staff's review of information submitted through May 19, 2011, the cutoff date for consideration in this SER. The one open item previously identified by the staff for the SER with open items have been closed (see SER Section 1.5); the staff did not identify any open items before the staff made a final determination. SER Section 6.0 provides the staff's final conclusion of the LRA review.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*

Hope Creek Generating Station
PSEG Nuclear, LLC
License renewal
Nuclear power plant
10 CFR Part 54
Docket No. 50-354
Aging Management
Scoping and Screening
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