Safety Evaluation Report

With Open Items Related to the License Renewal of Seabrook Station

Docket Number 50-443

NextEra Energy Seabook, LLC

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

June 2012

ABSTRACT

This safety evaluation report (SER) documents the technical review of the Seabrook Station (Seabrook) license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated May 25, 2010, NextEra Energy Seabook, LLC (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." NextEra Energy Seabrook, LLC requests renewal of the operating license (Facility Operating License Number NPF-86) for a period of 20 years beyond the current license period of March 15, 2030. Seabrook is located in the Town of Seabrook, Rockingham County, New Hampshire, on the western shore of Hampton Harbor, 2 miles west of the Atlantic Ocean. The station is approximately 2 miles north of the Massachusetts state line and approximately 15 miles south of the Maine state line.

A zero-power license was granted to the facility in October 1986, and a full-power operating license was subsequently granted on March 15, 1990. Seabrook previously sought and received a modification to the expiration of the facility operating license to recapture the time licensed at zero-percent power. The unit is a 4-loop pressurized-water reactor (PWR) design. General Electric Company supplied the nuclear steam supply system. Westinghouse constructed the plant. The licensed power output of the unit is 3,648 megawatts thermal, with a gross electrical output of approximately 1,245 megawatts electric. This SER presents the status of the staff's review of information submitted through May 16, 2012. The staff identified seven open items that must be resolved before any final determination can be made on the LRA. SER Section 1.5 summarizes the open items. The staff will present its final conclusion on the LRA review in an update to this SER.

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ABBREVIATIONS

AC	alternating current
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ADAMS	Agencywide Document Access and Management System
AERM	aging effect requiring management
AFW	auxiliary feedwater
AMP	aging management program
AMR	aging management review
AMS	ATWS mitigation system
ANS	American Nuclear Society
ANSI	American National Standards Institute
APCSB	Auxiliary and Power Conversion Systems Branch
AR	action request
ART	adjusted reference temperature
ASCE	American Society of Civil Engineers
ASFPC	alternate spent fuel pool cooling
ASM	American Society for Metals
ASME	American Society of Mechanical Engineers
ASR	alkali-silica reaction
AST	alternate source term
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
AWS	American Welding Society
AWWA	American Water Works Association
B&PV	boiler and pressure vessel
B&W	Babcock & Wilcox Company
B^{10}	boron-10
BTP	Branch Technical Position
BWR	boiling-water reactor
C	Celsius
CASS	cast austenitic stainless steel
CC	primary component cooling water system
CEA	control element assembly
cfm	cubic feet per minute
CFR	*Code of Federal Regulations*

CL	chlorination system
CLB	current licensing basis
cm^2	squared centimeter
CMTR	certified material test record
CO_2	carbon dioxide
CR	condition report
CRD	control rod drive
CRDM	control rod drive mechanism
CSR	cable spreading room
CSS	containment spray system
CST	condensate storage tank
Cu	copper
CUF	cumulative fatigue usage
CUF_{EN}	environmentally-correct CUF
CuNi	copper nickel
CVCS	chemical and volume control system
DBA	design-basis accident
DBD	design-basis document
DBE	design-basis event
DCI	division of component integrity
EAF	environmentally-assisted fatigue
ECCS	emergency core cooling system
EDB	equipment database
EDG	emergency diesel generator
EFPH	emergency feedwater pump house
EFPD	effective full power days
EFPY	effective full power years
EFW	emergency feedwater
EOL	end-of-life
EPA	Environmental Protection Agency
EPRI	Electrical Power Research Institute
EQ	environmental qualification
ER	environmental report
ESF	engineered safety feature
ESFAS	engineered safety features actuation system
F	Fahrenheit
FA	fire area
F_{EN}	environmental life correction factor

FERC	Federal Energy Regulatory Commission
FIV	flow-induced vibration
FPL	Florida Power and Light Company
FR	*Federal Register*
FRN	*Federal Register* Notice
FSAR	final safety analysis report
ft	foot
gal.	gallon
GALL	Generic Aging Lessons Learned
GDC	general design criterion
GEIS	generic environmental impact statement
GL	generic Letter
gpm	gallons per minute
GSI	generic safety issue
GSU	generator step-up
H_2	hydrogen
HELB	high-energy line break
HLSN	hot leg surge line nozzle
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning
I&C	instrumentation and control
IASCC	irradiation-assisted stress corrosion cracking
IEEE	Institute of Electronic and Electrical Engineers
IGSCC	intergranular stress corrosion cracking
IN	information notice
INPO	Institute of Nuclear Plant Operation
IPA	integrated plant assessment
ISA	independent safety analysis
ISG	interim staff guidance
ISI	inservice inspection
ksi	kips per square inch
kV	kilovolt
L	liter
lb	pound
LBB	leak-before-break
LOCA	loss-of-coolant accident

LOOP	loss of offsite power
LRA	license renewal application
LTOP	low temperature overpressure protection
MC	metal containment
MEAP	material, environment, aging effects, and aging management program
MEB	metal enclosed bus
MEQ	mechanical equipment qualification
MeV	million electron-volts
mg	milligram
MIC	microbiologically-influenced corrosion
MRP	Materials Reliability Program
MRule	Maintenance Rule
MSIP	mechanical stress improvement process
MSL	mean sea level
MWt	megawatt thermal
n/cm^2	neutrons per square centimeter
NACE	National Association of Corrosion Engineers
NaOH	sodium hydroxide
NEI	Nuclear Energy Institute
NextEra	NextEra Energy Seabrook, LLC
NFPA	National Fire Protection Association
NNS	non-nuclear safety
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSAS	non-safety affecting safety
NSSS	nuclear steam supply system
OBE	operating basis earthquake
ODSCC	outside-diameter stress corrosion cracking
OEM	original equipment manufactorer
OTSG	once-through steam generator
P&ID	piping and instrumentation diagram
PAH	primary auxiliary building air handling
ppb	parts per billion
ppm	parts per million
PRT	penetration resistance test
psi	pounds per square inch

psig	pounds per square inch gauge
PSL	pressurizer surge line
PSN	pressurizer surge nozzle
P-T	pressure-temperature
PTS	pressurized thermal shock
PVC	polyvinyl chloride
PVDF	polyvinylidene flouride
PWR	pressurized-water reactor
PWSCC	primary water stress corrosion cracking
QA	quality assurance
QAP	Quality Assurance Program
RAI	request for additional information
RAT	reserve auxiliary transformer
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
RIS	regulatory issue summary
RM	radiation monitoring system
RPS	reactor protection system
RPV	reactor pressure vessel
RS	resin sluicing system
RTD	resistance temperature detectors
RT_{NDT}	nil-ductility reference temperature
RT_{PTS}	PTS reference temperature
RV	reactor vessel
RVI	reactor vessel internals
RVID	Reactor Vessel Integrity Database
RWST	refueling water storage tank
SBO	station blackout
SC	structure and component
SCC	stress corrosion cracking
SCFM	standard cubic feet per minute
Seabrook	Seabrook Station Unit 1
SER	safety evaluation report

SF_6	sulfur hexaflouride
SFP	spent fuel pool
SG	steam generator
SI	safety injection
SO_2	sulfur dioxide
SOC	Statement of Consideration
SRP-LR	Standard Review Plan–License Renewal
SSC	system, structure, and component
SSE	safe shutdown earthquake
SSPS	solid state protection system
The Rule	Requirements for Renewal of Operating Licenses for Nuclear Power Plants
TLAA	time-limited aging analysis
TS	technical specification
TSTF	technical specification task force
UAT	unit auxiliary transformers
UFSAR	updated final safety analysis report
USE	upper-shelf energy
UT	ultrasonic testing
V	volt
WCAP	Westinghouse Commercial Atomic Power
WG	waste gas system
WL	waste processing liquid system
WLD	waste processing liquid drains system
WOG	Westinghouse Owners Group
Zn	zinc

SECTION 1

INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the license renewal application (LRA) for Seabrook Station Unit 1 (Seabrook), as filed by NextEra Energy Seabrook, LLC (the applicant). By letter dated May 25, 2010, the applicant submitted its application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the Seabrook Station Unit 1 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 Arthur Cunanan. Mr. Cunanan may be contacted by telephone at 301-415-3897, or by electronic mail at arthur.cunanan@nrc.gov. Alternatively, written correspondence may be sent to the following address:

Division of License Renewal
US Nuclear Regulatory Commission
Washington, D.C. 20555-0001
Attention: Arthur Cunanan, Mail Stop O11-F1

In its letter dated May 25, 2010, submission letter, the applicant requested renewal of the operating license issued under Section 103 (Operating License No. NPF-86) of the Atomic Energy Act of 1954, as amended, for Seabrook Station Unit 1 for a period of 20 years beyond the current expiration at midnight on March 15, 2030. Seabrook Station is located in Seabrook, New Hampshire on the western shore of Hampton Harbor, two miles west of the Atlantic Ocean. The NRC issued a zero power license in October 1986 and a full power operating license was subsequently granted on March 15, 1990. Seabrook Station employs a pressurized water reactor housed in a steel lined reinforced concrete containment structure which is enclosed by a reinforced concrete containment enclosure structure. The licensed power output was 3,411MWt; however, after implementing two power uprates, the rated thermal power has been increased to 3,648 MWt. The updated final safety analysis report (UFSAR) contains 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 Seabrook Station 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 and other docketed correspondence. Unless otherwise noted, the staff reviewed and considered information submitted through May 16, 2012. The staff reviewed information received after that date depending on the stage of the safety review and the volume and complexity of the information. 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). The LRA may also be viewed at Seabrook Library located at 25 Liberty Lane, Seabrook, New Hampshire 03874 or the Amesbury Public Library located at 149 Main Street, Amesbury, MA 01913. 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 licenses. 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, the staff will prepare a plant-specific supplement to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS)." This supplement discusses the environmental considerations for license renewal for Seabrook Station. The staff issued a draft, plant-specific GEIS Supplement in August 2011. The publication date of the final plant-specific GEIS Supplement is to be determined.

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 based on economic and antitrust considerations rather than on technical limitations; however, some individual plant and equipment designs may have been engineered for 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. As published May 8, 1995, in 60 FR 22461, 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 (61 FR 28467, 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.

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 exceptions of the detrimental aging effects on the functions 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, "Scope," defines the scope of license renewal as including those SSCs that (1) are safety-related, (2) whose failure could affect safety-related functions, or (3) are relied on to demonstrate compliance with the NRC's 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 perform an intended function without moving parts or without change in configuration or properties and are not subject to replacement based on a qualified life or specified time period. Pursuant to 10 CFR 54.21(a), a license renewal applicant must demonstrate that the aging effects will be managed such that the intended function(s) of those SCs will be maintained consistent with the current licensing basis (CLB) for the period of extended operation. However, active equipment is considered to be adequately monitored and maintained by existing programs. In other words, detrimental aging effects that may affect active equipment can be readily 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), the LRA is required to include an UFSAR supplement with a summary description of the applicant's programs and activities for managing aging effects and an 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 about the length of time the plant can operate are incorporated into design calculations for several plant SSCs. In accordance with 10 CFR 54.21(c)(1), the applicant must either 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 the aging effects on these SSCs will be adequately managed for the period of extended operation.

In 2005, the NRC revised 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. NEI 95-10 details an acceptable method of implementing 10 CFR Part 54. The staff also used the SRP-LR to review the LRA.

In the LRA, the applicant used the process defined in NUREG-1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report," dated September 2005. The GALL Report summarizes staff-approved aging management programs (AMPs) for many SCs subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources for LRA review can be greatly reduced, improving 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 of the SCs used throughout the industry. The report is also a quick reference for both applicants and staff reviewers to AMPs and activities that can manage aging adequately during the period of extended operation.

1.2.2 Environmental Review

Part 51 of 10 CFR contains regulations on environmental protection. 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 possible environmental impacts associated with nuclear power plant license renewals. For certain types of environmental impacts, the GEIS contains generic findings that apply to all nuclear power plants and are codified in Appendix B, "Environmental Effect of Renewing the Operating License of a Nuclear Power Plant," to Subpart A, "National Environmental Policy Act - Regulations Implementing Section 102(2)," of 10 CFR Part 51. Pursuant to 10 CFR 51.53(c)(3)(i), a license renewal applicant may incorporate these generic findings in its environmental report. In accordance with 10 CFR 51.53(c)(3)(ii), an environmental report also must include analyses of environmental impacts that must be evaluated on a plant-specific basis (i.e., Category 2 issues).

In accordance with the National Environmental Policy Act of 1969 and 10 CFR Part 51, the staff reviewed the plant-specific environmental impacts of license renewal, including whether there was new and significant information not considered in the GEIS. As part of its scoping process, the staff held public meetings on August 19, 2010 in Hampton, NH to identify plant-specific environmental issues. The staff issued the draft site-specific GEIS supplement on August 2011.The staff held another public meeting to discuss the draft, plant-specific supplement to the GEIS on September 15, 2011 in Hampton, NH. After considering comments on the draft, the staff will prepare and publish a final plant-specific GEIS supplement separately.

1.3 Principal Review Matters

Part 54 of 10 CFR describes the requirements for renewal of operating licenses for nuclear power plants. The staff's technical review of the LRA was in accordance with NRC guidance and 10 CFR Part 54 requirements. Section 54.29, "Standards for Issuance of a Renewed License," of 10 CFR sets forth the license renewal standards. This SER describes the results of the staff's safety review.

Pursuant to 10 CFR 54.19(a), the NRC requires a license renewal applicant to submit general information, which the applicant provided in LRA Section 1. The staff reviewed LRA Section 1 and finds that the applicant has submitted the required information.

Pursuant to 10 CFR 54.19(b), the NRC requires that the 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." On this issue, the applicant stated the following in the LRA:

> The current indemnity agreement No. B-106 for Seabrook Station states that the agreement shall terminate at the time of expiration of the license. The indemnity agreement lists NPF-86 as the applicable license number. Should the license number be changed upon issuance of the renewed license, NextEra Energy Seabrook requests that conforming changes be made to the indemnity agreement to include the extended period.

The staff intends to maintain the original license numbers upon issuance of the renewed licenses, 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, "Contents of Application - Technical Information," the NRC requires that the LRA contain: (a) an integrated plant assessment, (b) a description of any CLB changes during the staff's review of the LRA, (c) an evaluation of TLAAs, and (d) an 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).

Pursuant to 10 CFR 54.21(b), the NRC requires that, each year following submission of the LRA and at least three months before the scheduled completion of the NRC review, the applicant submit an LRA amendment identifying any CLB changes to the facility that affect the contents of the LRA, including the UFSAR supplement.

Pursuant to 10 CFR 54.22, "Contents of Application - Technical Specifications," the NRC requires that the LRA include changes or additions to the technical specifications (TS) that are necessary to manage aging effects during the period of extended operation. The applicant did not use Appendix D, thus indicating that no changes to the Seabrook Station TS are required to support the LRA.

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

As required by 10 CFR 54.25, "Report of the Advisory Committee on Reactor Safeguards," the ACRS will issue a report documenting its evaluation of the staff's LRA review and SER. SER Section 5 is reserved for the ACRS report when it is issued. SER Section 6 documents 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 staff's performance goals of maintaining safety, improving effectiveness and efficiency, reducing regulatory burden, and increasing public confidence. 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 GALL Report.

Table 1.4-1 shows the current set of ISGs, as well as the SER sections in which the staff addresses them.

Table 1.4-1. Current Interim Staff Guidance

ISG Issue (Approved ISG Number)	Purpose	SER Section
"Ongoing Review of Operating Experience" (LR-ISG-2011-05)	This LR-ISG clarifies the staff's existing position in the SRP-LR that acceptable license renewal AMPs should be informed and enhanced when necessary, based on the ongoing review of both plant-specific and industry operating experience.	SER Section 3.0.5
"Aging Management of Stainless Steel Structures and Components in Treated Borated Water" (LR-ISG-2011-01)	This final LR-ISG clarifies the staff's existing position on aging management in treated borated water.	SER Section 3.2.2.1

1.5 Summary of Open Items

As a result of its review of the LRA, including additional information submitted through May 16, 2012, the staff identified the following open items. An item is considered open if, in the staff's judgment, it does not meet all applicable regulatory requirements at the time of the issuance of this SER. The staff has assigned a unique identifying number to each open item.

OI 3.0.3.1.9-1
SER Section 3.0.3.1.9 — ASME Code Section XI, Subsection IWE Program

Due to the applicant's previous failure to maintain the annular space between the containment and containment enclosure buildings in a dewatered state, the staff is concerned that the applicant has not, until now, implemented procedures and inspection requirements to keep this area dewatered in the future. Accumulation of water in the annular space can potentially degrade the containment liner plate. The staff's concern is tracked as Open Item OI 3.0.3.1.9-1.

OI 3.0.3.2.18-1
SER Section 3.0.3.2.18 — Structures Monitoring Program

Based on the operating experience related to concrete degradation due to alkali-silica reaction (ASR), the staff is concerned that the applicant has not enhanced the Structures Monitoring Program to manage the effects of ASR. Until resolved, this issue is identified as OI 3.0.3.2.18-1.

OI B.1.4-2
SER Section 3.0.5 — Operating Experience

The applicant did not fully describe how it will use future operating experience to ensure that the AMPs will remain effective for managing the aging effects during the period of extended operation. In addition, some program descriptions contain no such statements and, for these AMPs, it is not clear whether the applicant intends to implement actions to monitor operating experience on an ongoing basis and use it to ensure the continued effectiveness of these AMPs. Further, the LRA does not state whether new AMPs will be developed, as necessary. Until resolved, this issue is identified as OI B.1.4-2.

OI 3.0.3.1.7-1
SER Section 3.0.3.1.7 — Bolting Integrity Program

In recent reviews of license renewal applications and operating experience, the NRC staff noted that seal cap enclosures can contain water leakage and therefore use of such enclosures should be accounted for in license renewal applications to ensure proper aging management. The applicant may have used, or currently uses, seal cap enclosures to contain water leakage. The staff noted that the use of such enclosures may not be accounted for in the LRA. For example, the environment within seal cap enclosures may be submerged, rather than the air environment of the original component design. Also, enclosures may prevent the direct inspections of bolting and component external surfaces within the Bolting Integrity and External Surfaces Monitoring Programs, respectively.

The staff lacks sufficient information to complete its evaluation of pressure-retaining bolting and component external surfaces surrounded by seal cap enclosures. Specifically, the LRA does not contain AMR items that address bolting and external surfaces in seal cap enclosure environments, which may be submerged due to ongoing leakage within the enclosure. It is also unclear how components within seal cap enclosures will be age-managed, since direct inspection is not possible. Furthermore, it is unclear to the staff whether seal cap enclosure configurations will be used in the period of extended operation. Until resolved, this issue is identified as OI 3.0.3.1.7-1.

OI 3.2.2.1-1
SER Section 3.2.2.1 — Treated Borated Water

The LRA contains several AMR items that manage stainless steel components exposed to treated borated water for loss of material, cracking, and reduction of heat transfer with the Water Chemistry Program. However, the staff noted that the associated treated borated water environments may not be controlled to less than 5 parts per billion (ppb) dissolved oxygen, and thus, the staff lacks sufficient information to conclude that these components will be adequately managed. Until resolved, this issue is identified as OI 3.2.2.1-1.

OI 4.2.4-1
SER Section 4.2.4 — Pressure-Temperature Limit

As a part of a separate licensing action on P-T limits, the applicant requested approval of P-T limits that would, based on an updated neutron fluence evaluation, extend the operating time of the current curves from 20 EFPY to 23.7 EFPY. The staff had concerns related to whether the methodology used to develop the P-T limits is consistent with the requirements in 10 CFR 50, Appendix G. Because the methodology used to develop the P-T limits during the initial operating period is the same as that to be used during the period of extended operation, this additional information is also pertinent to the review of LRA. Until resolved, this issue is identified as OI 4.2.4-1.

OI 3.0.3.2.2-1
SER Section 3.0.3.2 — Steam Generator Tube Integrity Program

The staff is concerned with the management of cracking due to primary water stress corrosion cracking (PWSCC) on the primary coolant side of steam generator tube-to-tubesheet welds that are made or cladded with nickel alloy. Also, the staff requested that the applicant provide information regarding its one-time inspection of the steam generator divider plate assembly in its UFSAR Supplement. Until resolved, this issue is identified as OI 3.0.3.2.2-1.

1.6 Summary of Confirmatory Items

As a result of its review of the LRA, including additional information submitted through May 16, 2012, the staff identified no confirmatory items (CI).

1.7 Summary of Proposed License Conditions

Following the staff's review of the LRA, including subsequent information and clarifications from the applicant, the staff identified 3 proposed license conditions.

The first license condition requires the applicant to include the UFSAR supplement required by 10 CFR 54.21(d) in the next UFSAR update, required by 10 CFR 50.71(e), following the issuance of the renewed licenses. The applicant may make changes to the programs and activities described in the UFSAR supplement provided the applicant evaluates such changes pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

The second license condition requires future activities described in the UFSAR supplement to be completed prior to the period of extended operation. The applicant shall complete these activities no later than six months prior to the PEO, and shall notify the NRC in writing when implementation of these activities is complete.

The third license condition requires that all capsules in the reactor vessel that are removed and tested meet the requirements of American Society for Testing and Materials (ASTM) E 185-82 to the extent practicable for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including spare capsules, must be approved by the staff prior to implementation. All capsules placed in storage must be maintained for future insertion. Any changes to storage requirements must be approved by the staff, as required by 10 CFR Part 50, Appendix H.

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 each license renewal application (LRA) to include 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 Seabrook Station Unit 1 (Seabrook) within the scope of license renewal and the SCs subject to an AMR. The staff reviewed the scoping and screening methodology of NextEra Energy Seabrook, LLC (NextEra or the applicant), to determine if 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 following:

- 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants" (the Rule)
- statements of consideration for the Rule (60 FR 222461)
- guidance of Nuclear Energy Institute (NEI) 95-10, Revision 6, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule," dated June 2005 (NEI 95-10)
- correspondence between the U.S. Nuclear Regulatory Commission (NRC), other applicants, and NEI

2.1.2 Summary of Technical Information in the Application

In LRA Sections 2 and 3, the applicant provided the technical information required by 10 CFR 54.4, "Scope," and 10 CFR 54.21(a). This safety evaluation report (SER) with open items, contains sections entitled "Summary of Technical Information in the Application," which provide information taken directly from the LRA.

In LRA Section 2.1, the applicant described the process used to identify the SSCs that meet the license renewal scoping criteria under 10 CFR 54.4(a) and the process used to identify the SCs that are subject to an AMR, 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:

- Section 2.2, “Plant Level Scoping Results”
- Section 2.3, “Scoping and Screening Results: Mechanical”
- Section 2.4, “Scoping and Screening Results: Structures and Structural Components”
- Section 2.5, “Scoping and Screening Results: Electrical and Instrumentation and Controls (I&C) Systems/Commodity Groups”

In LRA Section 3, “Aging Management Review Results,” the applicant described its aging management results as follows:

- Section 3.1, “Aging Management of Reactor Vessel, Internals, and Reactor Coolant System”
- Section 3.2, “Aging Management of Engineered Safety Features”
- Section 3.3, “Aging Management of Auxiliary Systems”
- Section 3.4, “Aging Management of Steam and Power Conversion Systems”
- Section 3.5, “Aging Management of Systems, Structures and Component Supports”
- Section 3.6, “Aging Management of Electrical and Instrumentation and Controls”

In LRA Section 4, “Time-Limited Aging Analyses,” the applicant provided its 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 10 CFR 54.21(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 SSCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) and 10 CFR 54.21(a)(2)

In addition, the staff conducted a scoping and screening methodology audit at Seabrook—located in the Town of Seabrook, Rockingham County, NH, on the western shore of Hampton Harbor, 2 miles (mi) west of the Atlantic Ocean—during the week of September 20–23, 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-level guidelines and topical reports 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 Appendix A, "Final Safety Analysis Report Supplement," and Appendix B, "Aging Management Programs," of the LRA. On a sampling basis, the staff performed a system review of the diesel generator, plant floor drain system (DF), roof drain system, service water system, spent fuel pool system, and feedwater system, including a review of the scoping and screening results reports and supporting design documentation used to develop the reports. The purpose of the staff's review was to ensure that the applicant had appropriately implemented the methodology outlined in the administrative controls and to verify that the 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 Trip Report, dated February 4, 2011, to verify that the process used to identify SCs subject to an AMR was consistent with the SRP-LR. Additionally, the staff reviewed the scope of CLB documentation sources 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 sources for the license renewal scoping and screening process:

- updated final safety analysis report (UFSAR)
- harsh environment equipment list
- maintenance rule (MRule) database
- design basis documents (DBDs)
- piping and instrumentation diagrams (P&IDs)
- electrical schematics
- station blackout (SBO) evaluation
- component database
- license renewal technical reports

2.1.3.1.2 Staff Evaluation

Scoping and Screening Implementing 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 the guidance is consistent with the requirements of the Rule, the SRP-LR, and Regulatory guide (RG) 1.188, "Standard Format and Content for Applications to Renew Nuclear Plant operating Licenses," which endorses the use of NEI 95-10. The staff finds 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 industry guidance.

The applicant's implementing procedures 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 procedures, the staff focused on the consistency of the detailed procedural guidance with information in the LRA, including the implementation of NRC staff positions documented in the SRP-LR, and the information in the applicant's February 3, 2011, response to the staff's January 5, 2011, requests for additional information (RAIs).

After reviewing the LRA, supporting documentation and the applicant's RAI responses, the staff determined that the scoping and screening methodology instructions are consistent with the methodology description provided in LRA Section 2.1. The applicant's methodology is sufficiently detailed to provide concise guidance on the scoping and screening implementation process to be followed during the LRA activities.

Sources of CLB 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 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, as well as 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 drawings. In addition, the applicant's license renewal process identified additional sources of plant information pertinent to the scoping and screening process, including the license renewal database, controlled drawings, and technical correspondence, analyses, and reports. In addition, the applicant had collected UFSAR, design basis information, drawings and other controlled information, appliable to specific systems, in documents refered to as "Design Basis Documents." The staff confirmed that the applicant's detailed license renewal program guidelines specified the use of the CLB source information in developing scoping evaluations.

The license renewal database, UFSAR, design basis information, and plant drawings were the applicant's primary repository for system identification and component safety classification information. During the audit, the staff reviewed the applicant's administrative controls for the license renewal database, design basis information, and other information sources used to verify system information. These controls are described, and implementation is governed, by plant administrative procedures. Based on a review of the administrative controls, and a sample of the system classification information contained in the applicable Seabrook documentation, the NRC staff concludes that the applicant has established adequate measures to control the integrity and reliability of Seabrook system identification and safety classification data. Therefore, the staff concludes that the information sources used by the applicant 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 explained the incorporation of updates to the CLB and the process used to ensure those updates are adequately incorporated into the license renewal database and license renewal documents. 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.

In addition, the staff reviewed the implementing procedures and results reports used to support identification of SSCs that the applicant 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 scoping and screening evaluations. The staff finds these design documentation sources to be useful for ensuring that the initial scope of SSCs identified by the applicant was consistent with the plant's CLB.

2.1.3.1.3 Conclusion

On the basis of its review of 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 CLB information in a manner consistent with the Rule, the SRP-LR, and NEI 95-10 guidance and, therefore, is acceptable.

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 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 controls used by the applicant to ensure that scoping and screening methodologies used to develop the LRA were adequately implemented. The applicant used the following quality control processes during the LRA development:

- using corporate and industry license renewal experience to guide the LRA development
- developing the LRA and performing associated activities using qualified and experienced personnel and assigning document reviewers based on subject matter expertise
- developing the LRA following NRC endorsed guidance, applicable industry standards, and Seabrook instructions and guidelines

- validating the LRA content with source documents by license renewal project leads
- reviewing the LRA using selected industry peers, the Seabrook Operations Review Committee, and site licensing department
- using a controlled and validated license renewal database for scoping and screening
- performing formal surveillance of LRA development activities by the Seabrook Nuclear Oversight Department
- using the Corrective Actions Program to report discrepancies in the plant equipment database and drawings

During the scoping and screening methodology audit, the staff reviewed the applicant's written procedures and quality control records and determined that the applicant had developed adequate procedures to control the LRA development and assess the results of the activities.

2.1.3.2.2 Conclusion

On the basis of its review of pertinent LRA development procedures and guidance, discussion with the applicant's license renewal staff, and 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 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 the guidelines and methodology for the scoping and screening activities were applied in a consistent and appropriate manner. As outlined in their implementing procedures, the applicant requires training for personnel participating in the development of the LRA. The activities conducted by the applicant included the following:

- training and qualification of personnel preparing, verifying, and approving license renewal documents in accordance with documented instructions
- assigning experienced plant personnel augmented with contracted personnel with license renewal experience to the License Renewal Project Team
- using orientation, computer based training, activity performance, and observation to accomplish training

During the scoping and screening methodology audit, the staff reviewed the applicant's written procedures and, on a sampling basis, reviewed completed qualification and training records and completed checklists for a sample of the applicant's license renewal personnel. The staff determined that the applicant 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 its review of selected documentation in support of the process, the staff concludes that the applicant's personnel were adequately trained and qualified to implement the scoping and screening methodology described in the applicant's implementing 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 scoping and screening implementing procedures, discussions with the applicant's license renewal personnel, review of the quality controls applied to the LRA development, training of personel participating in the LRA development, 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 described the applicant's methodology used to scope SSCs pursuant to the requirements of 10 CFR 54.4(a). The LRA states that the scoping process examined all SSCs with respect to license renewal. According to the LRA, SSCs were evaluated against criteria provided in 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) to determine if the item should be considered within the scope of license renewal. The LRA states that the scoping process identified the following SSCs:

- SSCs that are safety-related and perform or support an intended function for responding to a design basis event (DBE)
- SSCs that are nonsafety-related but their failure could prevent accomplishment of a safety-related function
- SSCs that support a specific requirement for one of the five regulated events applicable to license renewal

LRA 2.1 "Scoping and Screening Methodology," stated that the scoping methodology used by Seabrook is consistent with 10 CFR Part 54 and with the industry guidance contained in NEI 95-10.

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

2.1.4.1.1 Summary of Technical Information in the Application

LRA Section 2.1.2.1, "10 CFR 54.4(a)(1)—Safety-Related SSCs," states, in part:

> Systems, structures and components that perform safety functions as defined in 10 CFR 54.4(a)(1) are within the scope of license renewal. Safety-related SSCs are uniquely identified at Seabrook Station. The definition of Safety Related is consistent with the definition in 10 CFR 54.4, as follows:
>
> SSCs and related activities relied upon to remain functional during and following DBEs to ensure:
>
> - The integrity of the reactor coolant boundary,

- The capability to shut down the reactor and maintain it in a safe shutdown condition,
- The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to §50.34(a)(1), §50.67, or §100.11 of 10 CFR 50, as applicable. Seabrook Station has implemented Alternate Source Term (AST) with NRC approval. Therefore, §50.67 guidelines are applicable to Seabrook Station. (AST was not adopted for the [environmental qualification] EQ, however, the existing conditions are bounding.)

Components are classified as Safety Class 1, Safety Class 2, Safety Class 3, and non-nuclear safety (NNS) in accordance with their importance to nuclear safety. This importance, as established by the assigned safety class, is applied in the design, materials, manufacture or fabrication, assembly, erection, construction, and operation. A single system may have components in more than one safety class. The definitions of safety classes listed apply to fluid pressure boundary components and the reactor containment. Supports that have a nuclear safety function are of the same safety class as the components that they support. All Class 1E safety-related electrical, instrumentation and controls systems are Safety Class 3.

The Equipment Database (EDB) was initially used to identify the safety classification of systems, structures and components for license renewal per 10 CFR 54.4(a)(1).

Seabrook Station piping and instrumentation diagrams (P&IDs), Electrical One Line diagrams, Civil/Architectural drawings and the UFSAR were used to identify components required to support in-scope system-level and structure-level functions. As described in UFSAR section 3.2.2.2, safety class designation boundaries of safety-related systems are shown on the P&IDs and described in the respective sections of the UFSAR. Fluid system component safety class designations are listed in UFSAR Table 3.2-2. The Heating, Ventilation and Air Conditioning (HVAC) system component safety class designations are listed in UFSAR Table 3.2-4.

Seabrook Station structures, systems and components important to safety, as well as their foundations and supports, have been designed to withstand the effects of an Operating Basis Earthquake (OBE) and a Safe Shutdown Earthquake (SSE), and are thus designated as seismic Category I.

2.1.4.1.2 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:

- the integrity of the reactor coolant pressure boundary
- the ability to shut down the reactor and maintain it in a safe shutdown condition
- 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 identification of DBEs, Section 2.1.3, “Review Procedures,” of the SRP-LR states, in part:

> 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, design basis accidents (DBAs), external events, and natural phenomena) that were applicable to Seabrook. 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 Seabrook 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 was consistent with the SRP-LR.

The applicant performed scoping of SSCs for the 10 CFR 54.4(a)(1) criterion in accordance with the license renewal implementing procedures, which provide 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 it determined that the Seabrook CLB definition of safety-related met the definition of safety-related specified in the Rule. The staff reviewed a sample of the license renewal scoping results for the diesel generator, plant floor drain, roof drain system, service water system, spent fuel pool system, feedwater system, and turbine building to provide additional assurance that the applicant adequately implemented their 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 had 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) criteria.

The staff notes that Seismic Category I SSCs are designed to remain functional if the safe-shutdown earthquake (SSE) ground motion occurs.

2.1.4.1.3 Conclusion

On the basis of its review of systems (on a sampling basis), discussions with the applicant, and review of the applicant's scoping process, 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 2.1.2.2, “10 CFR 54.4(a)(2)—Non-Safety Related Affecting Safety-Related SSCs,” states, in part:

> 10 CFR 54.4(a)(2) requires that all non-safety related systems, structures and components whose failure could prevent satisfactory accomplishment of any of the functions identified in §54.4(a)(1) be included within the scope of license renewal. These SSCs are classified non-nuclear safety (NNS) in the Seabrook Station UFSAR and NNS is used interchangeably with the term Non-safety related.
>
> The process used at Seabrook Station for identification of Non-Safety Affecting Safety (NSAS) related SSCs is consistent with the NEI 95-10 “Industry Guideline for Implementing the Requirements of 10CFR54 – The License Renewal Rule,” Rev. 6, June 2005.
>
> SSCs required by §54.4(a)(2) for Seabrook Station are included in one of the following four categories:
>
> - Current Licensing Basis (CLB) Topics. The Seabrook Station CLB includes a number of topics that identify non-safety related SSCs credited for preventive or mitigative functions in support of safe shutdown for special events (e.g., external floods) or whose failure could prevent satisfactory accomplishment of a safety related function (e.g., seismic interactions). The CLB Topics are discussed in subsection 2.1.2.2.1.
> - Non-safety related SSCs directly connected to safety related SSCs are discussed in sub-section 2.1.2.2.2.
> - Non-safety related SSCs that are not directly connected to safety related SSCs but whose failure could prevent the satisfactory accomplishment of a safety related function due to spatial proximity. Non-Safety Related SSCs in spatial proximity of Safety Related SSCs are discussed in sub-section 2.1.2.2.3.
> - A non-safety related SSC could provide functional support for a safety related intended function. The non-safety related SSC is required to function so that a safety related SSC performs its intended function (e.g., a non-safety related system provides cooling to a safety related pump). Non-Safety Related SSCs providing functional support for safety related SSCs are discussed in sub-section 2.1.2.2.4.
>
> SSCs required by §54.4(a)(2) were identified by review of the Seabrook Station UFSAR and other CLB documentation. Plant drawings, DBDs, piping analyses, and the plant equipment database were also used. Plant walk downs were performed, as necessary, to confirm the spatial interaction boundaries.

LRA Section 2.1.2.2.1 states that the Seabrook CLB includes many topics that identify nonsafety-related SSCs credited for preventive or mitigative functions in support of safe shutdown for special events. Those topics include the following:

High Energy Line Break (HELB)

At Seabrook Station, the high energy piping systems were identified using the criteria if the service temperature is greater than 200° [Fahrenheit] F or the design pressure is greater than 275 [pounds per square inch gauge] psig. A HELB could affect EQ Equipment in the area of the break by increasing the local temperature and humidity.

All high-energy lines identified in UFSAR section 3, Appendix 3I are included as in-scope for license renewal. High energy lines of one-inch diameter or smaller pipe size were excluded from the HELB analysis but still remain as a potential source of spray and/or leakage. All of the HELB Analysis pipe segments are located in buildings with Safety Related equipment and are therefore in the scope of license renewal.

Protection from a high energy line break inside of buildings is provided primarily by separation and redundancy. High energy lines are routed to provide maximum protection by using plant structural elements, such as walls, columns, doors, and pipe whip restraints to prevent uncontrolled whipping of the high energy piping. Outside of buildings, protection from a high energy line break (postulated breaks in, or whip loads) is provided by seismic Category I reinforced concrete walls. These components are in-scope for license renewal.

Internal and External Flooding Events

Flooding from various internal sources (e.g., pipe breaks) and external sources were evaluated during the design of the plant. Protection against possible internal flooding from liquid carrying systems, due to pipe rupture or fire protection activities are discussed in Sections 3.6, 9.33, 9.5.1 and 10.4.5.3 of the UFSAR.

Internal Flooding features are associated with the Equipment and Floor Drainage System, including sumps, sump pumps, tanks, drains, and piping to remove water from potential internal flooding events, and fire protection activities for areas containing safety-related equipment. These design features are in-scope for license renewal. Protection against possible internal flooding is discussed in UFSAR Section 3.4 “Water Level (Flood) Design.” Internal flood protection components are reinforced concrete walls, and concrete and steel curbs. These components are in-scope for license renewal.

Protection against possible external flooding is discussed in UFSAR Sections 2.4.5.5 “Protective Structures,” and Section 2.5.5 “Stability of Slopes.” External flood protection components are stone revetment, sheet pile retaining wall, and vertical seawall. These components are in-scope for license renewal.

Internal and External Missile Hazards

> Missiles that could be generated from internal sources or external sources such as rotating equipment and tornados were considered in the design of the plant. Both preventive (e.g., over speed controls, seismic restraints) and mitigative (e.g., missile barriers) features were installed to ensure safe shutdown as required by the CLB for postulated missile hazards. These design features are in-scope for license renewal.
>
> Missiles that could be generated from internal or external sources as described in UFSAR Section 3.5 for various building and structures are summarized in UFSAR Table 3.5-1. The missile protection feature (missile barriers) are typically included as part of the building structure (reinforced concrete wall, floor or ceiling). All structures and their missile shields and barriers listed on UFSAR Table 3.5-12 are designed to resist internal and external missiles in accordance with the CLB, and are in-scope for license renewal.

LRA Section 2.1.2.2.2 states, in part, in relation to nonsafety-related directly connected to safety-related SSCs, the following:

> For NNS SSCs directly connected to safety related SSCs, the in-scope boundary for license renewal extends into the NNS portion of the piping and supports up to and including the first seismic anchor or an equivalent anchor beyond the safety/non-safety interface. An equivalent seismic anchor is a combination of pipe restraints as described in UFSAR Section 3.7 (B) and Figure 3.7 (B) – 37.
>
> An alternative used to specifically identify a seismic anchor or an equivalent anchor is to:
>
> - Include the NNS piping run to the next large piece of plant equipment (e.g., pump, heat exchanger, tank, etc). The large piece of equipment must also be included in-scope and is subject to aging management for the intended function of being an anchor point for the piping run.
> - Include the NNS piping run to a flexible connection – a flexible connection 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).
> - For NNS piping runs such as vent or drain piping that end at open floor drains, include the entire piping in the scope of LR.
> - For NNS piping runs that are connected to Safety Related (SR) piping at both ends, include the entire run of NNS piping between the SR piping.
> - Include the buried portion of the piping in the scope of license renewal up to the point where the buried pipe exits the ground.
>
> NNS structures attached to or next to Scoping Criteria 1 structures are in-scope for license renewal if their failure could prevent a Scoping Criteria 1 SSC from performing its intended function.

LRA Section 2.1.2.2.3 states, in part, in relation to nonsafety-related SSCs with the potential for spatial interaction with safety-related SSCs, the following:

For non-safety related NNS SSCs that are *not* directly connected to safety related SSCs, or are connected downstream of the first equivalent anchor, the non-safety SSCs may be in-scope if their failure could prevent the performance of the system safety function for which the safety related SSC is required.

Two approaches were used to determine if a non-safety related SSC in proximity to a safety related SSC is in scope for license renewal: the mitigative and preventive approach. Where it could be demonstrated that safety related SSCs are separated from non-safety related SSCs by physical barriers, the mitigative option was used (e.g., Tank Farm rooms TF101 and TF102). The preventive option was used in evaluating the vast majority of structures or systems at Seabrook Station for potential adverse structural or spatial interactions with Scoping Criterion 1 SSCs.

If a safety related component was determined to exist within that building, then all the NNS components within that building were included in the scope of LR. In other words, if a building contained a safety related component, then the entire building, not just the room, was included in the scope for NSAS.

There is one exception to the application of above methodology. NEI-95-10 Section 3.1.1 recognizes that…"a system, structure or component may not meet the requirements of §54.4(a)(1) although it is designated as safety related for plant specific reasons. However, the systems, structures and components would still need to be evaluated for inclusion into the scope of the Rule using the criteria in §54.4(a)(2) and §54.4(a)(3)."

The Turbine Building contains components associated with the reactor protection and engineered safety features actuation system which have been classified as safety related in the plant equipment database. There are no other safety related SSCs in the Turbine Building. These components do not perform a safety function, as defined in 10 CFR 54.4(a)(1), and are not credited in the Seabrook Station accident analysis. The CLB does not credit operation of these components during or after a seismic event and thus seismic design or qualification is not required. Therefore, there are no components in the Turbine Building that are considered to be in scope for license renewal as defined in 10 CFR 54.4(a)(2).

The Turbine Building is a non-seismic Category I structure (UFSAR 1.2.2.9). The entire Turbine Building is designed against failure due to Tornado Wind and SSE Loads that could affect any seismic Category I structures in the proximity and therefore considered to be in-scope for license renewal as defined in 10 CFR 54.4(a)(2) (UFSAR Tables 3.3-4 and 3.7(B)-22).

NNS Conduits, Trays, Junction Boxes, and Lighting Fixtures

NNS conduits, cable trays, junction boxes, lighting fixtures may contain or be routed near Scoping Criterion 1 cables or other components. To determine which of these commodities to consider in-scope for license renewal, a conservative simplified approach is used. All NNS conduits, trays, junction boxes and lighting fixtures and their supports located within structures housing safety related equipment are in-scope for license renewal.

> *NNS HVAC Ducts and Supports*
>
> At Seabrook Station, the non-nuclear safety (NNS) HVAC ducting was evaluated similar to air/gas piping systems utilizing the guidance provided in NEI 95-10 Appendix F. All HVAC duct supports located within structures housing Scoping Criterion 1 components are in-scope for license renewal similar to Air/Gas Systems.

LRA Section 2.1.2.2.4 states, in part, in relation to nonsafety SSCs providing functional support for safety-related SSCs, the following:

> The review of the CLB identified a diesel driven pump as a component that supports a safety related intended function. The portable Cooling Tower makeup pump is maintained on the site. It is capable of providing makeup water to the Service Water System (Section 2.3.3.37) Cooling Tower basin from the nearby Browns River or Hampton Harbor with several locations accessible by road. This pump is stored in a Seismic Category 1 building, and is used to ensure a 30 day supply of water in the cooling tower basin in the event of design bases event and subsequent seismic event, the Safe Shutdown Earthquake. This diesel driven pump (1-SW-P-329) has been included in the scope of license renewal.

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, for SSCs relied on to remain functional during and following a DBE to ensure the following:

- the integrity of the reactor coolant pressure boundary
- the ability to shut down the reactor and maintain it in a safe shutdown condition
- 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, 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 to include nonsafety-related SSCs that may have the potential to prevent satisfactory accomplishments of safety functions as follows: consideration of missiles, cranes, flooding, and HELBs; nonsafety-related SSCs connected to safety-related SSCs; nonsafety-related SSCs in proximity to safety-related SSCs; and mitigative and preventative options related to nonsafety-related and safety-related SSCs interactions.

In addition, the staff's position (as discussed in the SRP-LR Section 2.1.3.1.2) is that applicants need 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 Section 2.1.2.2 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 SSCs
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 Section 2.1.2.2.4 and the applicant's 10 CFR 54.4(a)(2) implementing document. The staff confirmed that the applicant had reviewed the UFSAR, plant drawings, the plant equipment 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 intended 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 LRA Section 2.1.2.2 and the applicant's 10 CFR 54.4(a)(2) implementing document. The applicant reviewed the safety-related to nonsafety-related interfaces for each mechanical system in order to identify the nonsafety-related components located between the safety 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 required to be structurally sound to maintain the integrity of the safety-related SSCs, 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
- equivalent anchors, as defined in the Seabrook UFSAR
- bounding conditions described in NEI 95-10 Revision 6, Appendix F (base-mounted component, flexible connection, inclusion to the free end of nonsafety-related piping, or inclusion of the entire 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 the LRA Section 2.1.2.2.3 and the applicant's 10 CFR 54.4(a)(2) implementing procedure. The applicant considered physical impacts (pipe whip, jet impingement) harsh environments, flooding, spray, and leakage when evaluating the potential for spatial interactions between nonsafety-related systems and safety-related SSCs. The staff further confirmed that the applicant used a preventative, spaces approach to identify the portions of nonsafety-related systems with the potential for spatial interaction with safety-related SSCs. The spaces approach focused on the interaction between nonsafety-related and safety-related SSCs that

are located in the same space, which was defined for the purposes of the review as a structure containing active or passive safety-related SSCs.

LRA Section 2.1.2.2.3 and the applicant's implementing document state that the applicant included mitigative features when considering the impact of nonsafety-related SSCs on safety-related SSCs for occurrences discussed in the CLB. The staff reviewed the applicant's CLB information—primarily contained in the UFSAR—related to missiles, crane load drops, flooding, and HELBs. The staff determined that the applicant also considered the features designed to protect safety-related SSCs from the effects of these occurrences through the use of mitigating features such as floor drains and curbs. The staff confirmed that the applicant included the mitigating features within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2).

LRA Section 2.1.2.2.3 and the applicant's implementing document state that the applicant 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 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 evaluated and determined not to contain 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 determined that additional information would be required to complete the review of the applicant's scoping methodology. RAI 2.1-1, dated January 5, 2011, states that during the scoping and screening methodology audit performed onsite September 20–23, 2010, the staff reviewed the LRA and the applicant's 10 CFR 54.4(a) implementing documents. The staff determined that the applicant identified and evaluated safety-related components located in the turbine building and that the applicant concluded that the nonsafety-related SSCs in the proximity of, or attached to, the safety-related SSCs were not required to be included within the scope of license renewal. The staff requested that the applicant do the following:

- identify SSCs located in the turbine building that are classified as safety-related in the plant EDB that were not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1)
- provide the details of the evaluation and the basis for the conclusion that SSCs, located in the turbine building that are classified as safety-related in plant EDB, do not have an intended function that requires the SSCs to be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1)
- provide the details of the evaluation and basis for the conclusion that nonsafety-related SSCs, in the proximity of or attached to SSCs located in the turbine building and classified as safety-related in plant EDB, are not required to be included within the scope of license in accordance with 10 CFR 54.4(a)(2)

The applicant responded to RAI 2.1-1 by letter dated February 3, 2011, which states, in part:

> The following components are classified as being safety-related and Class IE, are located in the non-seismic turbine building and are not included in the scope of license renewal in accordance with 10 CFR 54.4(a)(1).
>
>> Turbine Impulse Chamber Pressure Transmitters
>>
>> Turbine Steam Stop Valve Position Switches
>>
>> Turbine Steam Stop Valve Fluid Pressure Switches
>>
>> Turbine Steam Dump Valve Air Supply Solenoid Valves
>>
>> Feedwater Flow Control and Bypass Valve Position Switches
>>
>> Feedwater Flow Control and Bypass Valve Solenoid Valves

The applicant further stated in the February 3, 2011, letter, that the above components were evaluated and the basis for the conclusion that SSCs located in the turbine building that are classified as safety-related in the plant equipment database, do not have an intended function that requires these SSCs to be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) is documented below.

> The Turbine Impulse Chamber Pressure Transmitters inputs to the [Solid State Protection System] SSPS at Seabrook Station are designed such that the failure of these transmitters will not prevent actuation of the SSPS. They are designed as safety related so that they cannot prevent the SSPS from functioning. They are inputs to the Reactor Protection System and to the [anticipated transient without scram] ATWS Mitigating system and are not credited in the Seabrook Station accident analysis.
>
> The Turbine Impulse Pressure transmitters cannot prevent satisfactory accomplishment of any of the safety related functions discussed in 10 CFR 54.4(a)(1). Therefore the requirements of 10 CFR 54.4(a) (2) are not applicable.
>
> Turbine Steam Stop Valve Position Switches are classified as safety related, [however] their functioning is strictly anticipatory. Since these turbine steam stop valve limit and fluid pressure switches perform no safety function, are not credited in the accident analysis and meet Seabrook Station CLB for preventing interactions from propagating back into the [reactor protection system] RPS, they cannot prevent satisfactory accomplishment of any of the safety related functions discussed in 10 CFR 54.4(a)(1). Therefore the requirements of 10 CFR 54.4(a) (2) are not applicable.
>
> The Steam Dump System dump valve solenoids are classified as Class IE and safety related. The design criteria applied to the turbine stop valve limit switches and turbine hydraulic pressure sensors was also applied to the steam dump valve solenoids. While these solenoid valves are classified as safety related, UFSAR section 10.4.4.3, Safety Evaluation states: “The Steam Dump System is not essential to the safe operation of the plant. It is provided for flexibility of

operation." Since these Steam Dump system solenoids perform no safety function, are not credited in the accident analysis and meet Seabrook Station CLB for preventing interactions from propagating back into the RPS, they cannot prevent satisfactory accomplishment of any of the safety related functions discussed in 10 CFR 54.4(a)(1). Therefore the requirements of 10 CFR 54.4(a)(2) are not applicable.

Feedwater Flow Control and Bypass Valve Position Switches and circuits do not interface with either the RPS or the [engineered safety features actuation system] ESFAS. The position switches do not perform a safety function, are not credited for Accident Monitoring, and cannot prevent satisfactory accomplishment of any of the safety-related functions discussed in 10 CFR 54.4(a)(1). Therefore the requirements of 10 CFR 54.4(a) (2) are not applicable.

The Feedwater Regulating and Bypass Valves provide backup to the safety related feedwater isolation valves. Although the solenoids for the feedwater Regulating and Bypass valves are classified as safety related and Class IE, the valves themselves are classified as non-safety components. These valves are not credited for containment isolation but perform a non-safety related backup to the safety related feedwater water isolation function. Since these feedwater regulating and bypass valve solenoids are not credited for containment isolation, are not safety related per NUREG 0138 criteria and meet the Seabrook Station CLB for preventing interactions from propagating back into the ESFAS, they cannot prevent satisfactory accomplishment of any of the safety related functions discussed in 10 CFR 54.4(a) (1). However, since these feedwater regulating and bypass valve solenoids are credited as supporting a non-safety related backup isolation function for the feedwater isolation valves (closure of the non-safety feedwater regulating and bypass valves), the requirements of 10 CFR 54.4(a) (2) are applicable, i.e., the feedwater regulating and bypass valves must operate to support the feedwater isolation function. Additionally, the feedwater regulating and bypass valve solenoids are in scope of license renewal as being required to support 10 CFR 54.4(a) (3), Fire Protection (the intended function for Fire Protection is pressure boundary).

The staff reviewed the applicant's response to RAI 2.1-1 and determined that the applicant described the process used to evaluate systems that contained components that were identified as safety-related in the plant equipment database but that were not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The staff determined that, during the scoping process, the applicant identified components identified as safety-related in the plant equipment database that were contained in systems that, when evaluated by the applicant, were determined to not have safety-related intended functions that meet the criteria of 10 CFR 54.4(a)(1). The staff considered this information, along with information contained in the LRA and scoping implementing procedures, and determined that some components had been conservatively identified as safety-related in the plant equipment database although CLB information did not indicate that the plant system was required to perform an intended function meeting the criteria in 10 CFR 54.4(a)(1).

In addition, the staff determined that, during its review, the applicant had included the nonsafety-related feedwater and bypass solenoid valves, even though the valves are not credited for containment isolation, do perform a nonsafety-related backup to the safety-related feedwater water isolation function. The applicant also determined that the feedwater regulating and bypass valves support a 10 CFR 54.4(a)(3) function for fire protection (pressure boundary). The applicant revised the LRA to include the feedwater and bypass solenoids within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3).

The staff concludes—based on a review of the applicant's assessment of components identified as safety-related in the plant equipment database but whose parent system was not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1)—that the applicant provided an acceptable basis for not including the systems within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). RAI 2.1-1 is resolved.

The staff determined that additional information would be required to complete the review of the applicant's scoping methodology. RAI 2.1-2, dated January 5, 2011, states that during the scoping and screening methodology audit, performed onsite September 20–23, 2010, the staff determined that the applicant reviewed nonsafety-related drain lines in the proximity of safety-related SSCs and that the applicant concluded that the drain lines were not required to be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff determined that license renewal drawings included a note applicable to drain lines from relief valves that stated, "Lines are not liquid filled so they have no license renewal-intended function and are not in scope." The staff requested that the applicant provide the details of its evaluation and basis for its conclusion that nonsafety-related drain lines near safety-related SSCs will not be fluid-filled during a DBE, the failure of which could not prevent satisfactory accomplishment of the function of safety-related SSCs and, therefore, are not required to be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The applicant responded to RAI 2.1-2 by letter dated February 3, 2011, which states, in part, the following:

> The tailpipes for the non-safety related DF and [hot water heating system] HW relief valves shown in the above listed locations are not liquid filled during normal plant operation and were evaluated in accordance with the guidance provided in NEI 95-10, Rev 6, Section 5.2.2.1, "Systems and Components Containing Air/Gas."
>
> Additionally, the above listed non-safety related DF and HW system relief valves are not designed to operate nor lift during a design basis event. Furthermore, as stated in NUREG 1800, Section A.1 (Branch Technical Position RLSP-1), the applicable aging effects to be considered for license renewal include those that could result from normal plant operation, including plant/system operating transients and plant shutdown. Specific aging effects from abnormal events need not be postulated for license renewal.
>
> As stated above, as part of the integrated plant evaluation for license renewal, Seabrook Station determined that the normal internal environment for the downstream piping or tailpipes from the non-safety related relief valves is air-indoor uncontrolled. This decision was based on the conclusion that the subject relief valves were designed to limit potential over pressurization of the piping system, which is an extremely rare occurrence, if any at all. The valve set-points are rarely challenged, and therefore, it is a rare occurrence for a relief valve to lift. If a relief valve was to relieve and the downstream pipe become wetted, the pipe would dry over time and return to the air-indoor uncontrolled normal environment. Additionally, none of these relief valves are being utilized

> as a pressure control valve and therefore, the normal internal environment for the subject tail pipes is air-indoor uncontrolled (non-liquid).

The staff reviewed the applicant's response to RAI 2.1-2. The staff's review determined that the function of a drain line is to contain and pass fluid when required, and the pipe should be included within the scope of license renewal and subject to AMR in accordance with 10 CFR 54.4 (a)(2) for spatial interaction. The staff further determined that following inclusion of the drain lines within the scope of license renewal, the applicant's AMR will allow for the evaluation of material and environment combinations to identify aging effects and the suitability of AMPs. Subsequent to the initial response, the staff held a conference call with the applicant on April 8, 2011, to explain its concerns. By letter dated April 22, 2011, the applicant provided a revised response that states, in part, that "[b]ased on the teleconference held with the NRC on April 8, 2011, the tail pipes for the non-safety related relief valves have been added to the scope of license renewal under 10 CFR 54.4(a)(2) for spatial interaction."

The staff reviewed the applicant's response to RAI 2.1-2. The staff determined that the applicant appropriately amended the information in the LRA to include the nonsafety-related drain lines within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2). The staff's concern described in RAI 2.1-2 is resolved.

The staff determined that additional information would be required to complete the review of the applicant's scoping methodology. RAI 2.1-3, dated January 5, 2011, states that during the scoping and screening methodology audit performed onsite September 20–23, 2010, the staff reviewed the LRA and the applicant's 10 CFR 54.4(a) implementing documents, relative to nonsafety-related sump pumps. The staff noted that the license renewal implementing documents state that nonsafety-related sump pumps that are located in a sump are not included within the scope of license renewal if there is a cover over the sump preventing the pump from spatially interacting with safety-related equipment. The staff requested that the applicant provide the details of its evaluation and basis for the conclusion that the failure of nonsafety-related sump pumps, in the proximity safety-related SSCs, could not prevent satisfactory accomplishment of the function of safety-related SSCs and, therefore, are not required to be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The applicant responded to RAI 2.1-3 by letter dated February 3, 2011, which states, in part, the following:

> The sump pumps that are located in sumps that have a bolted down solid sump cover are not within the scope of license renewal for 10 CFR 54.4(a)(2). In these cases, the mitigative approach was utilized as the bolted down solid plate would prevent liquid spray from components inside the sump. Steel or stainless steel sump cover plates that are fixed in place are considered part of the building structure and age managed under the Structures Monitoring Program, B.2.1.31, as part of the carbon steel or stainless steel commodity grouping.
>
> All sump locations were reviewed to ensure that this approach was applied consistently. This review identified that four sumps did not have a solid sump cover. Therefore, the sump pumps and piping inside these sumps were brought into the scope for license renewal. These sumps are located in the East and West Main Steam and Feedwater Pipe Chases and Intake and Discharge Transition Structures. On LRA drawing PID-1-DFLR20200, sump pumps P-51A,

> P-51B, P-267A, P-267B, P-268A, and P-268B and associated piping in the sumps should have been colored Green instead of Black.
>
> The above listed four pumps are not utilized to mitigate internal flooding events. The nonsafety related sump pumps, piping, and valves that are necessary to mitigate the effects of internal flooding events and fire protection activities in areas containing safety related equipment are in scope of license renewal for 10 CFR.54(a)(2) or 10 CFR.54(a)(3) regardless of the type of sump covers they have.

The staff reviewed the applicant's response to RAI 2.1-3. The staff's review determined that for nonsafety-related sump pumps with permanently attached covers, the applicant had appropriately included the permanently attached sump pump covers as a mitigating feature to prevent spatial interaction, in accordance with 10 CFR 54.4(a)(2). In addition, during its review, the applicant identified four nonsafety-related sump pumps that did not have permanently attached covers. In these cases, the applicant revised the LRA to include the sump pump and associated piping within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). RAI 2.1-3 is resolved.

Based on its review of the LRA, the results of the scoping and screening methodology audit and the applicant's reponses to RAIs 2.1-1, 2.1-2, and 2.1-3, the staff confirmed that fluid-filled nonsafety-related SSCs, in proximity to safety-related SSCs and whose failure could potentially prevent accomplishement of a safety function, 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, discussions with the applicant, and review of the information provided in the response to RAIs 2.1-1, 2.1-2, and 2.1-3, 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 2.1.2.3, "10 CFR 54.4(a)(3)—Regulated Events," states, in part:

> The third scoping category in 10 CFR 54.4 involves SSCs relied upon by licensees to address five regulated events. Specifically, §54.4(a)(3) defines SSCs as in-scope for license renewal, if relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with one or more of the regulated events:
>
> - Fire Protection (10 CFR 50.48)
> - Environmental Qualification (EQ) (10 CFR 50.49)
> - Anticipated Transient Without Scram (10 CFR 50.62)
> - Station Blackout (10 CFR 50.63)
> - Pressurized Thermal Shock (10 CFR 50.61)

Any SSC that is required to function in order to meet compliance requirements of one or more of these regulations was identified as required by §54.4(a)(3).

Fire Protection Scoping

All systems, structures and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48) were included in the scope of License Renewal in accordance with 10 CFR 54.4(a)(3) requirements.

The scope of systems and structures required for compliance with 10 CFR 50.48 are described in UFSAR Appendix A and Appendix R. They include:

- Systems and structures required to demonstrate safe shutdown capabilities.
- Systems and structures required for fire detection and suppression needed to support safe shutdown.
- Systems and structures required to meet commitments made to Appendix A of Branch Technical Position [Auxiliary and Power Conversion Systems Branch] APCSB 9.5-1 with respect to the protection of systems important to safety and prevention of radioactive releases to the environment.

The License Renewal fire protection technical report documents the results of a detailed review of Seabrook Station's fire protection program documents that demonstrate compliance with the requirements of 10 CFR 50.48. This document provides a list of systems and structures credited in the plant's fire protection and safe shutdown evaluations. The identified systems and structures are in the scope of License Renewal under 10 CFR 54.4(a)(3) scoping criteria.

Environmental Qualification Scoping

The CLB for Seabrook Station's EQ Program is Title 10, Part 50, Section 49 of the *Code of Federal Regulations* (10 CFR 50.49). This is achieved via conformance to the requirements of NUREG-0588, "*Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment*" Category I criteria. Category I criteria incorporates and supplements [Institute of Electrical and Electronics Engineers] IEEE 323-1974, "*IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.*"

The EQ portion of the license renewal scoping was performed utilizing the Harsh Environment Equipment list. Systems and structures containing equipment within the scope of the EQ Program were identified. The buildings serve to provide shelter, support and protection of EQ equipment. Components in the EQ program are evaluated in the EQ TLAA, Section 4.4.

Anticipated Transients Without Scram Scoping

10 CFR 54.4(a)(3) requires that all systems, components and structures relied on in safety analyses or plant evaluations to perform a function that demonstrates

compliance with the Commission's regulations for Anticipated Transients Without Scram (ATWS) (10 CFR 50.62) be included in the scope of license renewal.

An ATWS Mitigation System (AMS) is installed at Seabrook Station which provides an alternative means for automatically tripping the turbine and actuating Emergency Feedwater (EFW) flow that is independent of the protection system actuations.

Seabrook Station SSCs used to mitigate an ATWS event have been included in the scope of License Renewal.

Station Blackout Scoping

10 CFR 54.4(a)(3) requires that all systems, structures and components relied upon in safety analyses or plant evaluations to perform a function that is credited in demonstrating compliance with the Commission's regulations for Station Blackout (10 CFR 50.63) be included in the scope of License Renewal.

Seabrook Station complies with the requirements of 10 CFR 50.63 as a coping plant. This means that safe shutdown can be maintained using battery backed electrical buses for the four hour coping period. Offsite power and or onsite power will be restored at or before the end of the four hour coping period.

The SBO Offsite Recovery Path License Renewal Drawing, Figure 2.5-1, was created to depict the in-scope portion of the off-site power system for Station Blackout (SBO). Seabrook Station has chosen two paths for the recovery of off-site power in the event of a Station Blackout (SBO). Path 1 is colored green. Path 2 is colored red.

Pressurized Thermal Shock

Criterion 10 CFR 54.4(a)(3) requires that all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for [pressurized thermal shock] PTS be included in the scope of License Renewal.

Pressurized Thermal Shock (PTS) is a condition that could challenge the integrity of the reactor pressure vessel (RPV). Pressurized Thermal Shock (PTS) may occur during a severe transient such as a Loss of Coolant Accident (LOCA) or a steam line break.

The steel reactor vessel beltline shell, including plates, forgings, and welds, were determined to meet the scoping criteria of 10 CFR 54.4 with respect to pressurized thermal shock.

2.1.4.3.2 Staff Evaluation

The staff reviewed the applicant's approach to identifying SSCs, in accordance with 10 CFR 54.4(a)(3), which are relied on to perform functions meeting the requirements of the NRC regulations regarding fire protection, EQ, ATWS, PTS, and SBO. As part of this review, the staff did the following:

- discussed the applicant's methodology
- reviewed the boundary drawings
- reviewed license renewal technical reports associated with the five regulated events
- reviewed the LRA for the development and approach taken to complete the scoping process for these regulated safety systems
- evaluated SSCs (on a sampling basis) included within the scope of license renewal pursuant to 10 CFR 54.4(a)(3)

The staff confirmed that the applicant's implementing procedures were used for identifying Seabrook SSCs within the scope of license renewal pursuant to 10 CFR 54.4(a)(3). The applicant evaluated the Seabrook CLB and other source documents to identify SSCs that perform functions addressed in 10 CFR 54.4(a)(3), "Regulated Events," and included these SSCs within the scope of license renewal, as documented in the specific Seabrook regulated event(s) license renewal technical reports. The staff determined that these technical report results appropriately reference the information sources used for determining the SSCs credited for compliance with the events listed in the specified regulations for the applicable license renewal regulated events.

<u>Fire Protection</u>. The staff determined that the applicant's fire protection scoping document identified SSCs in the scope of license renewal required for fire protection. Seabrook used CLB documents to identify the SSCs within the scope of license renewal for fire protection, primarily the UFSAR, Section 9.5.1, "Fire Protection Systems." The staff reviewed the source documents used by the applicant including the UFSAR and the Seabrook fire protection-related design basis documents. The staff reviewed the fire protection scoping and screening report in conjunction with the LRA and the CLB information to validate the methodology for including the appropriate SSCs within the scope of license renewal. The staff determined that the applicants scoping included SSCs that perform intended functions to meet the requirements of 10 CFR 50.48. Based on its reviews, the staff determined that the applicant's scoping methodology was adequate for including SSCs credited in performing fire protection functions within the scope of license renewal.

<u>EQ</u>. The staff confirmed that the applicant's EQ scoping and screening report 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), 10 CFR 50.49(b)(2), and 10 CFR 50.49(b)(3). The staff determined that the applicant used the CLB, as described in the Seabrook UFSAR Section 3.11, as well as its EQ DBD to identify SSCs necessary to meet the requirements of 10 CFR 50.49. The Seabrook Harsh Environment Equipment List contains the EQ identifications for specific components. The staff reviewed the LRA, implementing procedures, and the EQ scoping and screening report to verify that the applicant identified SSCs within the scope of license renewal that meet EQ requirements. Based on that review, the staff determined that the applicant's scoping methodology was adequate for identifying EQ SSCs within the scope of license renewal.

<u>PTS</u>. The staff confirmed that the applicant's PTS scoping and screening report included the applicant's scoping methodology that used Seabrook CLB information to develop the LRA to comply with 10 CFR 50.61, "PTS Rule," which resulted in the Seabrook reactor vessel beltline components to be within the scope of license renewal pursuant to 10 CFR 54.4(a)(3). The staff reviewed the "Seabrook Station Reactor Pressure Vessel Fluence Evaluation at 55 [Effective Full Power Years] EFPY," which provides the basis for identifying the specific components

in-scope for license renewal. The staff determined that the methodology applied was appropriate for identifying SSCs with functions credited for complying with the PTS regulation and within the scope of license renewal. The staff finds that the scoping results included the systems and structures that perform intended functions to meet the requirements of 10 CFR 50.61. The staff determined that the applicant's scoping methodology was adequate for including SSCs credited in meeting PTS requirements within the scope of license renewal

ATWS. The staff determined that the applicant's ATWS scoping and screening report included the plant systems credited for ATWS mitigation based on review of the Seabrook CLB and the UFSAR, Section 7.6.12, "ATWS Mitigation System," and Section 15.8, "Anticipated Transients Without Scram." The staff reviewed these documents and the LRA in conjunction with the scoping results to confirm the methodology for identifying ATWS systems and structures that are within the scope of license renewal. The staff determined that the scoping results included systems and structures that perform intended functions meeting 10 CFR 50.62 requirements. The staff determined that the applicant's scoping methodology was adequate for identifying SSCs with functions credited for complying with the ATWS regulation.

SBO. The staff determined that the applicant's SBO scoping and screening report included SSCs from the Seabrook CLB that the applicant identified were associated with coping and safe shutdown of the plant following an SBO event by reviewing UFSAR Section 8.4, "Compliance With 10 CFR 50.63, Loss of All Alternating Current Power (Station Blackout)," and plant procedures. The staff reviewed a sample of these documents and the LRA, in conjunction with the scoping results, to confirm 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 in complying with the SBO regulations within the scope of license renewal.

2.1.4.3.3 Conclusion

On the basis of the sample reviews, discussions 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

System and Structure Level Scoping. LRA Section 2.1, "Scoping and Screening Methodology," states, in part:

> "Scoping" was performed to identify the plant systems and structures which perform intended functions as defined in 10 CFR 54.4(a)(1), (a)(2) or (a)(3). Initially, all Seabrook Station SSCs were examined. If any portion of a system or structure met the scoping criteria of 10 CFR 54.4, the system and/or structure was included in-scope for License Renewal. For systems and structures determined to be in scope, the intended functions were identified. All electrical and Instrumentation and Control systems and components are considered in scope.

> "Screening" was performed to identify the components associated with the in-scope systems and structures that are subject to aging management review as defined in 10 CFR 54.21. The screening process examined in-scope components and structures to determine those that are passive and long-lived. These components and structures were subject to aging management review.
>
> Scoping and screening has been performed consistent with the requirements of 10 CFR 54, the Statements of Consideration related to the license renewal rule, and the guidance provided in NEI 95-10, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule, Revision 6."

LRA Section 2.1.2, "Scoping Methodology," states, in part:

> The scoping methodology utilized by Seabrook Station is consistent with the guidance provided by NEI 95-10, Revision 6. Existing plant documentation was used for this review including the Updated Final Safety Analysis Report (UFSAR), Technical Specifications and licensing correspondence that collectively form the Seabrook Station Current Licensing Basis (CLB). Additional information sources included Design Basis Documents (DBD's), controlled drawings, Equipment Database and the Maintenance Rule Database.
>
> All Seabrook Station plant systems and structures were reviewed and evaluated against the scoping criteria to determine which met the requirements for inclusion in the scope of license renewal.
>
> Scoping was initially performed at the system or structure level in accordance with the criteria identified in 10 CFR 54.4(a). System level and structure intended functions were then identified from a review of CLB documentation. Starting at the system level intended functions, scoping boundaries for each system were determined. The results of this effort form the basis for identification of the in-scope components.
>
> Component information was initially transferred from the Seabrook Station Equipment Database (EDB) to the License Renewal Database. The EDB is used to maintain configuration control of component level information at Seabrook Station. As such, quality assurance applied to the EDB software ensures compliance with requirements and/or commitments that are necessary to support both safety related and non-nuclear safety component level information.
>
> Equipment that is stored on site for use in response to design basis events is considered to be within the scope of License Renewal. At Seabrook Station, Station Blackout and Appendix R fire scenarios utilize stored equipment to facilitate contingency actions following the event. The stored equipment is confirmed available and in good operating condition by periodic inspection. Tools and supplies used to place the stored equipment in service are not in the scope of License Renewal.

LRA Section 2.1.2 further states, in part:

> Application of all three 10CRF54.4 criteria generated a listing of SSCs that were determined to be in-scope for license renewal. Not every component of a system

supports the system intended functions. Therefore, some components within an in-scope system are not in-scope for license renewal.

For the mechanical scoping effort, summary level boundary descriptions were developed and included in Section 2.3. License Renewal drawings/diagrams were also created from plant controlled PID’s to illustrate in-scope mechanical systems, structures and components subject to an aging management review (AMR). These AMR boundaries are depicted on color coded license renewal drawings (e.g. PID-1-FW-LR20686) and contain system boundary flags.

For the electrical scoping effort, boundary drawings were not necessary since commodity grouping was used in the scoping process. The SBO Offsite Recovery Path License Renewal Drawing, Figure 2.5-1, was created to depict the in-scope portion of the off-site power system for Station Blackout (SBO).

2.1.4.4.2 Staff Evaluation

The staff reviewed the applicant’s methodology for performing the scoping of plant systems and components to ensure it was consistent with 10 CFR 54.4. The methodology used to determine the systems and components 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 applicant documented the results of the plant-level scoping process in accordance with the implementing documents. The results were provided in the systems and structures documents and reports, which contained the following information:

- a description of the structure or system
- 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
- 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

On the basis of its review of the LRA, site guidance documents, and a sampling of system scoping results reviewed during the audit, the staff concludes that the applicant’s methodology for identifying SSCs within the scope of license renewal, and their intended functions, is consistent with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.5 Mechanical Scoping

2.1.4.5.1 Summary of Technical Information in the Application

LRA Section 2.1.2, "Scoping Methodology," states, in part, the following with regard to mechanical scoping:

> Mechanical scoping utilized existing Maintenance Rule (MRule) system functions during the License Renewal scoping. These functions were transferred into the License Renewal Database from the MRule database. In addition to the MRule functions, functions were created in the License Renewal Database to capture the non-safety affecting safety (Criterion 2) and the five regulated events (Criterion 3). The MRule system functions that were transferred to the License Renewal Database were validated for accuracy using the UFSAR, Technical Specifications, DBDs (including source documents), and other controlled documentation.

2.1.4.5.2 Staff Evaluation

The staff evaluated LRA Section 2.1.2, "Scoping Methodology," and the guidance in the implementing procedures and reports to perform the review of the mechanical scoping process. The project documents and reports provided instructions for identifying the evaluation boundaries. The staff reviewed the implementing documents and the CLB documents associated with mechanical system scoping, and it finds that the guidance and CLB source information noted above were acceptable to identify mechanical components and support structures in mechanical systems that are within the scope of license renewal. The staff conducted discussions with the applicant's license renewal project personnel and reviewed documentation pertinent to the scoping process during the scoping and screening methodology audit. The staff assessed whether the applicant 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 the LRA Section 2.1.2 and the guidance contained in the SRP-LR, Section 2.1, and was adequately implemented.

On a sampling basis, the staff reviewed the applicant's scoping and screening reports for the diesel generator, plant floor drains, roof drain system, service water system, spent fuel pool system, feedwater system, and mechanical component types that met the scoping criteria of 10 CFR 54.4. The staff also reviewed the implementing procedures and discussed the methodology and results with the applicant. The staff verified that the applicant identified and used pertinent engineering and licensing information in order to determine that the mechanical component types are required to be within the scope of license renewal. As part of the review process, the staff evaluated each system's intended function, the basis for inclusion of the intended function, and the process used to identify each of the system component types. The staff verified that the applicant identified and highlighted system P&IDs to develop the license renewal boundaries in accordance with the procedural guidance. Additionally, the staff determined that the applicant independently verified the results in accordance with the governing procedures. The staff confirmed that the applicant had license renewal personnel knowledgeable about the system, and these personnel performed independent reviews of the marked-up drawings to ensure accurate identification of system-intended functions. The staff also confirmed that the applicant 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, and the sampling system review of mechanical scoping results, the staff concludes that the applicant's methodology for identifying mechanical SSCs within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.6 Structural Scoping

2.1.4.6.1 Summary of Technical Information in the Application

LRA Section 2.1.2, "Scoping Methodology," states, in part, the following with regard to civil and structural scoping:

> Civil controlled drawings and the EDB were used to identify buildings, structures and foundations. The buildings were input into the License Renewal Database as individual or grouped license renewal structures. Other information sources, such as CLB documentation, were electronically searched using several keywords (e.g., structure, new structure, building modification) to ensure all plant structures were evaluated for license renewal-intended functions regardless of their coverage in the plant equipment database.

2.1.4.6.2 Staff Evaluation

The staff evaluated LRA Section 2.1.2, "Scoping Methodology," implementing procedures and guidelines, and scoping and screening reports to perform the review of the structural scoping process. The license renewal procedures and guidelines provided instructions for identifying the evaluation boundaries. 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 identified and developed a list of plant structures and the structures intended functions through a review of plant equipment database, UFSAR, drawings, and walkdowns. Each structure the applicant identified was evaluated against the criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

The staff reviewed CLB information, drawings, and implementing procedures to verify the adequacy of the methodology for identifying structures meeting the scoping criteria as defined in the rule. The staff discussed the methodology and results with the applicant. In addition, the staff reviewed, on a sampling basis, the applicant's scoping and screening reports including information contained in the source documentation to verify that the application of the methodology would provide the results documented in the LRA.

In a specific example, the staff verified that the applicant identified and used pertinent engineering and licensing information to determine that the nonsafety-related turbine building was included within the scope of license renewal based on it housing and supporting safety-related components. As part of the review process, the staff evaluated the intended functions identified for the turbine building and the structural components within, 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 implementation procedures, and a sampling review of structural scoping results, the staff concludes that the applicant's methodology for identification of the structural SSCs within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.7 Electrical Component Scoping

2.1.4.7.1 Summary of Technical Information in the Application

LRA Section 2.1.2, "Scoping Methodology" states, in part, the following with regard to electrical and I&C scoping:

> All electrical and I&C systems were considered in-scope. Electrical and I&C components were organized into commodity groups. The information provided by NEI 95-10 Appendix B and NUREG-1800 Table 2.1-5, was used as a basis for categorizing electrical and I&C components into commodity groups such as insulated cables and connections, circuit breakers, and switches. Individual components were not identified.
>
> The electrical commodity groups identified resulted from a review of plant documents; controlled drawings, the EDB, and interface with the parallel mechanical screening efforts.

2.1.4.7.2 Staff Evaluation

The staff evaluated LRA Section 2.1.2 and the 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, CLB documentation, documents, procedures, drawings, specifications, and codes and standards.

The staff noted that, after the scoping of electrical and I&C components was performed, the in-scope electrical components were categorized into electrical component types. Component types include similar electrical and I&C components with common characteristics. Component-level intended functions of the component types were identified—such as cable, connections, fuse holders, terminal blocks, high-voltage transmission conductor, connections and insulators, metal enclosed bus, switchyard bus, and connections.

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 included electrical and I&C components and also electrical and I&C components contained in 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, scoping implementing procedures, scoping bases documents, and a sampling review of electrical scoping results, the staff concludes that the applicant's methodology for the scoping of electrical components 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 sampling review of 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 that are within the scope of license renewal in accordance with 10 CFR 54.4(a)(1)–10 CFR 54.4(a)(3). 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 2.1.3, "Screening Methodology," states, in part:

> Structures and components (or component commodity groups) that perform an intended function without moving parts or without a change in configuration or properties are defined as passive for License Renewal.
>
> Passive structures and components that are not subject to replacement based on a qualified life or specified time period are defined as long-lived for License Renewal. The screening process was used to identify the passive, long-lived structures and components in the scope of License Renewal and subject to aging management review. The Seabrook Station screening process determines the structures and components subject to aging management review by:
>
> - Listing the in-scope structures and components by component type,
> - Screening component types by using the passive and long lived criteria, and
> - Identifying the intended functions performed by these structures and components by component type.
>
> NUREG-1800, "*Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants*" and NEI 95-10, Appendix B were used as the basis for the identification of passive structures and components. Most passive structures and components 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 (e.g., solenoid valves that are periodically replaced).

Intended functions used to define passive structures and components are identified in LRA Table 2.1-1. Structures and components may have multiple intended functions (e.g., heat exchanger with heat transfer and pressure boundary-intended functions). Seabrook Station has considered multiple intended functions where applicable, consistent with the staff guidance provided in Tables 2.1-4(a) and (b) of NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." If a component did not have at least one component-level intended function, the component was not subject to an aging management review.

Detailed scoping and screening reports have been prepared which identify all structures and components subject to an aging management review. These reports have been prepared for all systems, structures, or commodity groups (except electrical commodities) in-scope for License Renewal.

Passive, long lived electrical commodities subject to an aging management review were identified using guidance in NEI 95-10.

The Seabrook Station structures and components subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.21(a)(1).

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 (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 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 2.1.3, the applicant discusses these screening activities as they related to the component types and commodity groups within the scope of license renewal.

The staff determined that the 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 Systems," LRA Section 2.4, "Scoping and Screening Results: Structures," and LRA Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Controls Systems (I&C) Systems/Commodity Groups." These sections of the LRA provided the results of the process used to identify component types and commodity groups subject to an AMR. The staff also reviewed, on a sampling basis, the screening results reports for safety injection (SI) and shutdown cooling, diesel generator fuel oil storage and transfer, auxiliary feedwater, and the turbine building.

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 specific methodology for mechanical, electrical, and structural is discussed in SER Sections 2.1.5.2 through 2.1.5.4.

2.1.5.1.3 Conclusion

On the basis of a review of the LRA, the implementing procedures, and a sampling of screening results, the staff concludes that the applicant's screening methodology is consistent with the guidance contained in the SRP-LR and is 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 are subject to an AMR is consistent with the requirements of 10 CFR 54.21 and, therefore, is acceptable

2.1.5.2 Mechanical Component Screening

2.1.5.2.1 Summary of Technical Information in the Application

LRA Section 2.1.3 states, in part, the following with regard to mechanical screening:

> Mechanical components have been screened with the system in which they were scoped. Plant components such as heat exchangers and coolers that have License Renewal-intended functions that are unique have been identified at the subcomponent level to ensure all the intended functions and material / environment combinations are considered in the evaluation (e.g., channel head, shell, tubes, and tube sheet).

2.1.5.2.2 Staff Evaluation

The staff reviewed the mechanical screening methodology discussed and documented in LRA Section 2.1.3, the implementing documents, the scoping and screening reports, and the license renewal drawings. The staff determined that the mechanical system screening process began with the results from the scoping process and that the applicant reviewed each system evaluation boundary as depicted on the P&IDs 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 an intended function within the system evaluation boundaries and determined those components to be subject to an AMR. The results of the review were documented in the scoping and screening reports, which contain information such as the information sources reviewed and the component intended functions.

The staff verified that mechanical system evaluation boundaries were established for each system within the scope of license renewal and that the boundaries were determined by mapping the system-intended function boundary onto P&IDs. 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.

During the scoping and screening methodology audit, the staff reviewed selected portions of the UFSAR, plant equipment database, CLB documentation, Seabrook databases and 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 also performed a walkdown of portions of the selected systems with plant engineers to verify documentation. The staff assessed whether the mechanical screening methodology outlined in the LRA and procedures was appropriately implemented and if the scoping results were consistent with CLB requirements. In addition, during the scoping and screening methodology audit, the staff discussed the screening methodology with the applicant and, on a sampling basis, reviewed the applicant's screening reports for the diesel generator, plant floor drains, roof drain system, service water system, spent fuel pool system, and feedwater system 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.

2.1.5.2.3 Conclusion

On the basis of its review of the LRA, the screening implementation procedures, selected portions of the UFSAR, plant equipment database, CLB documentation, procedures, drawings, specifications and selected scoping and screening reports, and a sample of the SI and shutdown cooling system, diesel generator fuel oil storage and transfer system, and auxiliary feedwater system, the staff concludes that the applicant's methodology for identification of mechanical 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.

2.1.5.3 Structural Component Screening

2.1.5.3.1 Summary of Technical Information in the Application

LRA Section 2.1.3 states, in part, the following with regard to civil and structural screening:

> The screening process was applied to in-scope buildings and civil structures to identify the structural elements to be evaluated in the aging management reviews.
>
> The Seabrook Station scoping and screening process used a "spaces" approach in establishing the evaluation boundaries. With few exceptions, the scoping and screening boundary for a building or structure is an entire building or buildings, including the doors, supports, base slabs, foundations, walls, beams, slabs, roofs, penetration seals and structural steel. The various types of structural elements, and materials that make up the buildings were identified and listed. The listing of structural elements is facilitated by grouping them into component groups. Structural components/commodities often do not have unique identifiers such as those given to mechanical components. Therefore, identifying structural components as commodities based on materials of construction, their environment and functional applications provided an identification system for aging management reviews.
>
> A list of structural commodities (example; carbon steel with indoor air includes, but is not limited to: carbon steel decking, embedments, fasteners, grating, other miscellaneous steel such as fire walls made from carbon steel siding, doors, plates, platforms, rails for hoists, and shapes) was developed for each civil/structural evaluation boundary. Structural commodities that perform an intended function without moving parts and without a change in configuration or

> properties, and that are not subject to replacement based on a qualified life or specified time period, are subject to aging management review.

2.1.5.3.2 Staff Evaluation

The staff reviewed the structural screening methodology discussed and documented in LRA Sections 2.1.3, implementing procedures and guidelines, scoping and screening reports, and the license renewal structures drawing. The staff reviewed the applicant's commodity group methodology for identifying structural components that are subject to an AMR, as required in 10 CFR 54.21(a)(1). The staff confirmed that the applicant 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, structure system information, and scoping and screening reports the applicant used to perform the structural scoping and screening. The staff also reviewed screening activities, on a sampling basis, that documented the SCs within the scope of license renewal. The staff conducted detailed 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 was appropriately implemented and if the scoping results were consistent with CLB requirements.

2.1.5.3.3 Conclusion

On the basis of its review of information contained in the LRA, implementing procedures and guidelines, plant equipment database, and a sampling of the structural screening results, the staff concludes that the applicant's 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 2.1.3 states the following, in part, in regard to electrical screening:

> Screening of electrical and I&C components used a bounding approach as described in NEI 95-10. All Electrical and I&C systems were considered in-scope. Electrical and I&C components were assigned to a commodity grouping. The commodity groups subject to an aging management review were identified by applying the criteria of 10 CFR 54.21(a)(1). This method provided the most efficient means for determining the electrical commodity groups subject to an aging management review since many of the electrical components are active.
>
> The sequence of steps used by Seabrook Station for identification of electrical commodity groups that require an aging management review included the following:
>
> (1) The criteria of 10 CFR 54.21(a)(1)(i) was applied to identify commodity groups that perform their intended functions without moving parts or without a change in configuration or properties (referred to as "passive"

components). These electrical commodity groups were identified utilizing the guidance of NEI 95-10.

(2) Portions of electrical commodity groups that perform no License Renewal-intended functions do not require aging management review and were not considered further (e.g., ground conductors, switchyard components outside of SBO boundary).

(3) The screening criterion found in 10 CFR 54.21(a)(1)(ii) excludes those commodity groups that are subject to replacement based on a qualified life or specific time period from the requirements of an aging management review. The 10 CFR 54.21(a)(1)(ii) screening criterion was applied to those commodity groups that were not previously eliminated by application of the 10 CFR 54.21(a)(1)(i) criteria or because they do not perform a License Renewal-intended function.

(4) The electrical commodities that require an aging management review are passive electrical commodities. The passive commodity groups that are not subject to replacement based on a qualified life or specified time period (long-lived) are subject to an aging management review.

2.1.5.4.2 Staff Evaluation

The staff reviewed the applicant's methodology used for electrical component screening in LRA Sections 2.1.3 and 2.5, the applicant's implementing procedures, bases documents, and electrical AMR 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 identified commodity groups that met the passive criteria in accordance with NEI 95-10. In addition, the staff determined that the applicant evaluated the identified, passive commodities to determine if 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 remaining passive, long-lived components were determined to be subject to an AMR.

The staff performed a review to determine if the screening methodology outlined in the LRA and implementing procedures were appropriately implemented and if the scoping results were consistent with CLB requirements. During the scoping and screening methodology audit, the staff reviewed selected screening reports and discussed the reports with the applicant to verify proper implementation of the screening process. Based on these onsite review 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 the screening implementation procedures, selected portions of the UFSAR, 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 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.

2.1.5.5 Screening Methodology Conclusion

On the basis of its review of the LRA, the screening implementing procedures, discussions with the applicant's staff, and a sample review of screening results, the staff concludes that the applicant's screening methodology was consistent with the guidance contained in the SRP-LR and 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, sample system reviews, and the applicant's responses dated February 3, 2011, to the staff's RAIs, the staff confirms that the applicant's scoping and screening methodology is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). The staff also concludes that the applicant's description and justification of its scoping and screening methodology are adequate to meet the requirements of 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

In LRA Section 2.1, the applicant described the methodology for identifying SSCs within the scope of license renewal. In LRA Section 2.2, the applicant used the scoping methodology to determine which SSCs must be included within the scope of license renewal. The staff reviewed the plant-level scoping results to determine if the applicant has properly identified the following:

- all systems and structures relied upon to mitigate DBEs, as required by 10 CFR 54.4(a)(1)
- systems and structures whose failure could prevent satisfactory accomplishment of any safety-related functions, as required by 10 CFR 54.4(a)(2)
- systems and structures relied on in safety analyses or plant evaluations to perform functions required by regulations referenced in 10 CFR 54.4(a)(3)

2.2.2 Summary of Technical Information in the Application

In LRA Table 2.2-1, the applicant listed plant mechanical, electrical and I&C systems, and structures within the scope of license renewal. Based on the DBEs considered in the plant's 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

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 its evaluation is provided 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 Tables 2.2-1, "Systems and Structures within the Scope of License Renewal," and 2.2-2, "Systems and Structures Not in the Scope of License Renewal" to confirm that there were no omissions of plant-level systems and structures 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 verify if 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 noted that, in LRA Section 2.3.3.45, the waste process building is indicated as being not in-scope for license renewal. However, in LRA Section 2.4.5, the applicant states that the waste process building is in-scope for 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) and is included in Table 2.2-1. By letter dated January 5, 2011, the staff issued RAI 2.2-01 and requested that the applicant clarify if the waste process building is within the scope of license renewal.

In its response dated February 3, 2011, the applicant stated that the waste process building is within scope of license renewal and provided a revised LRA Section 2.3.3.45 to indicate that the waste process building is in-scope.

Based on its review, the staff finds the applicant's response to RAI 2.2-01 acceptable because the applicant revised LRA Section 2.3.3.45 to specify that the waste process building is within scope of license renewal. Therefore, the staff's concern described in RAI 2.2-01 is resolved

2.2.4 Conclusion

On the basis of its review of the LRA Section 2.2, the RAI response, and the UFSAR supporting information to determine whether the applicant failed to identify any systems and structures within the scope of license renewal, 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.

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 (RCS)
- 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 it took into account, where applicable, the system functions described in the UFSAR. The objective was to determine if the applicant 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 SCs that have functions performed with moving parts or a change in configuration or properties or 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 RAIs.

2.3.1 Reactor Vessel, Internals, and Reactor Coolant System

LRA Section 2.3.1 identifies 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 RCS in the following LRA sections:

- Section 2.3.1.1, "Reactor Coolant (RC) System"
- Section 2.3.1.2, "Reactor Vessel (RV)"
- Section 2.3.1.3, "Reactor Vessel Internals (RVI)"
- Section 2.3.1.4, "Steam Generators (SG)"

The staff's findings on review of LRA Sections 2.3.1.1–2.3.1.4 are provided in SER Sections 2.3.1.1–2.3.1.4, respectively.

2.3.1.1 Reactor Coolant System

2.3.1.1.1 Summary of Technical Information in the Application

The reactor coolant (RC) system consists of four heat transfer loops connected in parallel to the reactor pressure vessel. Each loop contains a reactor coolant pump, a steam generator, and associated piping and valves. In addition, the RC system includes a pressurizer, pressurizer relief tank, pressurizer relief and safety valves, interconnecting piping, and instrumentation necessary for operational control.

During operation, the RC system transfers the heat generated in the core to the steam generators, where steam is produced to drive the turbine generator. Borated demineralized water is circulated in the RC system at a flow and temperature consistent with achieving the reactor core thermal-hydraulic performance. The water acts as a neutron moderator and as a neutron absorber. The RC system pressure is controlled by the use of the pressurizer, where water and steam are maintained in equilibrium by electrical heaters and water sprays.

The RC system pressure boundary provides a barrier against the release of radioactivity generated within the reactor and is designed to ensure a high degree of integrity throughout the life of the plant.

The intended functions of the RC system component types within the scope of license renewal include the following:

- serve as a pressure boundary and limit the release of fission products
- provide RC system pressure control and limit pressure transients
- provide the borated water used as a neutron moderator and as a neutron absorber
- provide a containment isolation function

The following license renewal drawings provide the details of SSCs for the scope of license renewal and subject to an AMR:

- PID-1-CS-LR20722
- PID-1-RH-LR20662
- PID-1-SI-LR20450
- PID-1-VSL-LR20777
- PID-1-WLD-LR20221
- PID-1-RC-LR20841–PID-1-RC-LR20846
- PID-1-RH-LR20663
- PID-1-SS-LR20518
- PID-1-WLD-LR20218
- PID-1-SI-LR20448
- PID-1-SS-LR20520
- PID-1-WLD-LR20219

LRA Table 2.3.1-1 lists the RC system components types that require AMR.

2.3.1.1.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA and UFSAR, the staff concluded that the applicant appropriately identified the RC system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the RC system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.2 Reactor Vessel

2.3.1.2.1 Summary of Technical Information in the Application

The reactor vessel is a vertical cylinder with a welded hemispherical bottom head and a removable, flanged hemispherical upper head. The vessel contains the core, core supporting structures, control rods, and other parts directly associated with the core. The vessel has four inlet and four outlet nozzles located in a horizontal plane just below the reactor vessel flange but above the top of the core. The coolant enters the vessel through the inlet nozzles, flows down the core barrel-vessel wall annulus, turns at the bottom, and flows up through the core to the outlet nozzles.

Both the upper and lower reactor vessel heads contain penetrations, which are used for instrumentation or control devices. The lower reactor vessel head has penetrations for 58 incore nuclear instrumentation thimbles, while the reactor vessel upper head contains 79 control rod drive mechanism (CRDM) penetrations.

The reactor vessel is supported by steel pads on four of the coolant nozzles. The steel pads rest on steel base plates atop a support structure that is attached to the concrete foundation wall. There are three lifting lugs evenly spaced around the upper head, which are used to move it.

The intended functions of the reactor vessel component types within the scope of license renewal include the following:

- serve as a pressure boundary for containing reactor coolant
- provide a barrier against the release of radioactivity
- support and contain the reactor core and core support structures
- support and guide reactor controls and instrumentation
- mitigate thermal shock

The following license renewal drawing provides the details of SSCs for the scope of license renewal and subject to an AMR:

- PID-1-RC-LR20845

LRA Table 2.3.1-2 lists the reactor vessel components types that require AMR.

2.3.1.2.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA and UFSAR, the staff concluded that the applicant appropriately identified the reactor vessel components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the reactor vessel components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.3 Reactor Vessel Internals

2.3.1.3.1 Summary of Technical Information in the Application

The reactor vessel internals are divided into three parts—the lower core support structure, the upper core support structure, and the incore instrumentation support structure.

The reactor vessel internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and CRDM, direct coolant flow past the fuel elements, direct coolant flow to the pressure vessel head, provide gamma and neutron shielding, and provide guides for the incore instrumentation.

The lower core support structure assembly consists of the core barrel, the core baffle, the lower core plate and support columns, the neutron shields pads, the core support that is welded to the core barrel, reactor fuel, and rod cluster control assemblies. The upper core support assembly consists of the top support plate assembly and the upper core plate, between which are contained support columns and guide tube assemblies. The incore instrumentation support structure consists of a guide tubing system to convey and support flux thimbles penetrating the vessel through the bottom.

The intended functions of the reactor vessel internals components types within the scope of license renewal include the following:

- support the reactor core
- maintain fuel alignment between fuel assemblies and control rods
- direct coolant flow to the vessel head
- provide gamma and neutron shielding
- guide the incore instruments

LRA Table 2.3.1-3 lists the reactor vessel internals component types that require AMR.

2.3.1.3.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA and UFSAR, the staff concluded that the applicant appropriately identified the reactor vessel internals components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the reactor vessel internals components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.4 Steam Generators

2.3.1.4.1 Summary of Technical Information in the Application

The steam generators transfer heat from the RC system to the secondary system during normal plant conditions, producing steam for use in the turbine generator. Each steam generator includes a primary section called the tube side, which includes components such as hemispherical channel head with a divider plate, tube sheet, and U-tubes. The channel head makes up the bottom of the steam generator. The shell of the steam generator is a vertical cylinder. The tube sheet is welded to the bottom of the cylinder. The secondary section of the steam generator is referred to as the shell side. The upper shell houses the moisture separation equipment. The steam-water mixture from the tube bundle passes through the moisture separator equipment to ensure that high-quality steam is produced by the steam generators.

The intended functions of the steam generator component types within the scope of license renewal include the following:

- transfer heat from the RC system to the secondary systems
- provide RC system pressure boundary function
- confine radioactive material

The following license renewal drawings provide the details of the SSCs for the scope of license renewal and subject to an AMR:

- PID-1-FW-LR20686
- PID-1-RC-LR20841–PID-1-RC-LR20844
- PID-1-MS-LR20580
- PID-1-MS-LR20581

LRA Table 2.3.1-4 lists the steam generator components types that require AMR.

2.3.1.4.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA and UFSAR, the staff concluded that the applicant appropriately identified the steam generator components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the steam generator components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features

LRA Section 2.3.2 identifies the engineered safety features SCs subject to an AMR for license renewal.

The applicant described the supporting SCs of the engineered safety features in the following LRA sections:

- Section 2.3.2.1, “Combustible Gas Control (CGC) System”
- Section 2.3.2.2, “Containment Building Spray (CBS)System”
- Section 2.3.2.3, “Residual Heat Removal (RH) System”
- Section 2.3.2.4, “Safety Injection (SI) System”

The staff’s findings on review of LRA Sections 2.3.2.1–2.3.2.4 are provided in SER Sections 2.3.2.1–2.3.2.4, respectively.

2.3.2.1 Combustible Gas Control System

2.3.2.1.1 Summary of Technical Information in the Application

LRA Section 2.3.2.1 describes the combustible gas control system, which consists of subsystems that monitor the combustible gas concentrations in the containment and maintain a mixed containment atmosphere to ensure that hydrogen (H_2) concentrations remain below flammable levels following a LOCA. This is achieved by monitoring containment H_2 levels, mixing the containment atmosphere, recombining free H_2 with oxygen, or purging the containment atmosphere.

The containment atmosphere is monitored by two completely independent H_2 sampling and analysis systems, which are started after an accident. One means of combustible gas control in the containment is through the use of electric H_2 recombiners. Seabrook has a pair of recombiners, located at the perimeter of the operating floor inside the containment. Purging is accomplished by venting the containment gas and replacing it with clean compressed air from the plant air system. Compressed air is fed into the containment.

2.3.2.1.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the combustible gas control system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the combustible gas control system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.2 Containment Building Spray System

2.3.2.2.1 Summary of Technical Information in the Application

The containment building spray system is designed to remove the energy discharged to the containment following a LOCA or main steam line break, to prevent the containment pressure from exceeding design pressure, and to reduce and maintain containment temperature and pressure within acceptable limits. The containment building spray system provides for iodine removal by mixing sodium hydroxide (NaOH) with borated water from the refueling water storage tank (RWST) to limit the consequences of a LOCA to within the limits of 10 CFR Part 100 by providing a rapid reduction in containment elemental iodine concentration. The limits on NaOH volume and concentration ensure a pH value of between 8.5–11.0 for the solution recirculated within containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components.

2.3.2.2.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the containment building spray system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the containment building spray system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.3 Residual Heat Removal System

2.3.2.3.1 Summary of Technical Information in the Application

The residual heat removal (RH) system transfers heat from the RCS to the primary component cooling water system to reduce the temperature of the RCS to the cold shutdown temperature, at a controlled rate, during the normal plant cooldown. The RH system is provided with two RHR pumps and two residual heat exchangers arranged in two separate and independent flow paths.

The RH system also makes up the low-head SI portion of the emergency core cooling system (ECCS) by injecting borated water from the RWST into the RCS cold legs during injection phase following a LOCA. The RH system is also used to transfer water between the refueling cavity and the RWST at the beginning and end of the refueling operations.

The intended functions of the RH system component types within the scope of license renewal include the following:

- form a part of the RCS pressure boundary
- remove decay heat in post-accident and normal shutdown conditions
- provide protection against over-pressurization and rupture of ECCS low pressure piping that could result in a LOCA
- provide borated water for RCS makeup in LOCA conditions

The following license renewal drawings provide the details of SSCs for the scope of license renewal and subject to an AMR:

- PID-1-CBS-LR20233
- PID-1-RC-LR20841
- PID-1-RH-LR20663
- PID-1-VSL-LR20776
- PID-1-CS-LR20722
- PID-1-RC-LR20844
- PID-1-CS-LR20725
- PID-1-SI-LR20446–PID-1-RH-LR20662
- PID-1-WLD-LR20221
- PID-1-SI-LR20450

LRA Table 2.3.2-3 lists the RH system component types that require AMR.

2.3.2.3.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the RH system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the RH system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.4 Safety Injection System

2.3.2.4.1 Summary of Technical Information in the Application

The safety injection (SI) system provides emergency core cooling to the reactor core as a part of the ECCS. The ECCS consists of three separate subsystems—centrifugal charging (high head), SI (intermediate head), and RH (low head). Each subsystem consists of two redundant, 100 percent capacity trains. The ECCS also includes four accumulators (one on each RCS loop) and the RWST.

The SI system consists of accumulators, SI pumps, RWST, and associated piping and valves. Four accumulators, which are filled with borated water and pressurized with nitrogen gas, are connected to the four cold legs. The SI system has two phases of operation—the injection phase and the recirculation phase.

The injection phase provides core cooling and additional negative reactivity following actuation. The SI pumps take their suction from the RWST during injection phase. The recirculation phase provides long-term post-accident cooling by recirculating water from the containment sump.

The intended functions of the SI system component types within the scope of license renewal include the following:

- form part of the RCS pressure boundary
- provide source of emergency core cooling in response to a LOCA
- provide containment isolation function
- protect against over-pressurization and rupture of ECCS low pressure piping
- provide mechanical support for safety-related SSCs

The following license renewal drawings provide the details of the SSCs for the scope of license renewal and subject to an AMR:

- PID-1-BRS-LR20854
- PID-1-RC-LR20844
- PID-1-SI-LR20446–PID-1-SI-LR20450
- PID-1-WLD-LR20219
- PID-1-CBS-LR20233
- PID-1-RH-LR20662–PID-1-RH-LR20663
- PID-1-WLD-LR20221
- PID-1-RC-LR20841
- PID-1-WLD-LR20218

LRA Table 2.3.3-4 lists the SI component types that require AMR.

2.3.2.4.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the SI system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the SI system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3 Auxiliary Systems

LRA Section 2.3.3 identifies the auxiliary systems SCs subject to an AMR for license renewal.

The applicant described the supporting SCs of the auxiliary systems in the following LRA sections:

- Section 2.3.3.1, “Auxiliary Boiler (AB) System”
- Section 2.3.3.2, “Boron Recovery (BRS)System”
- Section 2.3.3.3, “Chemical and Volume Control (CS) System”
- Section 2.3.3.4, “Chlorination (CL) System”
- Section 2.3.3.5, “Containment Air Handling (CAH) System”
- Section 2.3.3.6, “Containment Air Purge (CAP) System”
- Section 2.3.3.7, “Containment Enclosure Air Handling (EAH) System”
- Section 2.3.3.8, “Containment Online Purge (COP) System”
- Section 2.3.3.9, “Control Building Air Handling (CBA) System”
- Section 2.3.3.10, “Demineralized Water (DM) System”
- Section 2.3.3.11, “Dewatering (DW) System”
- Section 2.3.3.12, “Diesel Generator(DG) System”
- Section 2.3.3.13, “Diesel Generator Air Handling (DAH) System”
- Section 2.3.3.14, “Emergency Feed Water Pump House Air Handling (EPA) System”
- Section 2.3.3.15, “Fire Protection (FP) System”
- Section 2.3.3.16, “Fuel Handling (FH) System”
- Section 2.3.3.17, “Fuel Oil (FO) System”
- Section 2.3.3.18, “Fuel Storage Building Air Handling (FAH) System”
- Section 2.3.3.19, “Hot Water Heating (HW) System”
- Section 2.3.3.20, “Instrument Air (IA) System”
- Section 2.3.3.21, “Leak Detection (LD) System”
- Section 2.3.3.22, “Mechanical Seal Supply (MSS) System”
- Section 2.3.3.23, “Miscellaneous Equipment (MM)”
- Section 2.3.3.24, “Nitrogen Gas (NG) System”
- Section 2.3.3.25, “Oil Collection for Reactor Coolant Pumps (OC) System”
- Section 2.3.3.26, “Plant Floor Drain (DF) System”
- Section 2.3.3.27, “Potable Water (PW) System”
- Section 2.3.3.28, “Primary Auxiliary Building Air Handling (PAH) System”
- Section 2.3.3.29, “Primary Component Cooling Water (CC) System”
- Section 2.3.3.30, “Radiation Monitoring (RM) System”
- Section 2.3.3.31, “Reactor Makeup Water (RMW) System”
- Section 2.3.3.32, “Release Recovery (RR) System”
- Section 2.3.3.33, “Resin Sluicing (RS) System”
- Section 2.3.3.34, “Roof Drains (DR) System”
- Section 2.3.3.35, “Sample (SS) System”
- Section 2.3.3.36, “Screen Wash (SCW) System”
- Section 2.3.3.37, “Service Water (SW) System”
- Section 2.3.3.38, “Service Water Pump House Air Handling (SWA) System”
- Section 2.3.3.39, “Spent Fuel Pool Cooling (SF) System”
- Section 2.3.3.40, “Switchyard (SY) System”
- Section 2.3.3.41, “Valve Stem Leak-off (VSL) System”
- Section 2.3.3.42, “Vent Gas (VG) System”
- Section 2.3.3.43, “Waste Gas (WG) System”
- Section 2.3.3.44, “Waste Processing Liquid (WL) System”
- Section 2.3.3.45, “Waste Processing Liquid Drains (WLD) System”

The staff’s findings on review of LRA Sections 2.3.3.1–2.3.3.45 are provided in SER Sections 2.3.3.1–2.3.3.45, respectively.

During its review, the staff identified instances of boundary drawing errors where continuation notation for piping from one boundary drawing to another boundary drawing could not be identified or was incorrect.

By letter dated January 5, 2011, the staff issued RAI 2.3-01 and noted 13 instances where the staff was unable to identify the license renewal boundary because either the continuations were not provided or were incorrect or the continuation drawing was not provided. The applicant was asked to provide additional information to locate the continuations.

In its response dated February 3, 2011, the applicant provided sufficient information to locate the license renewal boundaries. No additional piping or component types were included in the scope of license renewal. The applicant also indicated that no continuation drawings were needed for piping that terminated at the nearby floor drains. The applicant described stated components such as instrumentation and components found on vendor drawings were already included within the scope of license renewal but not depicted on the LRA drawings.

Based on its review, the staff finds the applicant's response to RAI 2.3-01 acceptable. No additional systems or components were required to be added to the scope of license renewal. Therefore, the staff's concern described in RAI 2.3-01 is resolved.

2.3.3.1 Auxiliary Boiler

2.3.3.1.1 Summary of Technical Information in the Application

The auxiliary boiler system is a subsystem of the auxiliary steam system. The auxiliary boiler system provides steam to the auxiliary steam system, which in turn provides process steam for various plant heating loads.

There are two main purposes of the auxiliary boiler system: to provide steam to the auxiliary steam system and to provide fuel oil to the fire pump house boiler. The fire pump house boiler provides steam to heat the fire water storage tank and provides steam to the fire pump house unit heaters.

The auxiliary boiler system consists of two package boilers, which include a de-aerating heater with storage tank, boiler feed pumps, fuel oil pumps, and a blowdown tank. Also included are the fuel oil storage tank and the associated piping. The portion of the auxiliary boiler system that supplies oil to the fire pump house boiler consists of piping from the fuel oil storage tank to the fire pump house boiler and the fire pump house boiler oil pumps.

2.3.3.1.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the auxiliary boiler system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the auxiliary boiler system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.2 Boron Recovery System

2.3.3.2.1 Summary of Technical Information in the Application

The boron recovery system stores and processes reactor coolant effluent and reactor coolant grade drainage for reuse in the plant or for disposal offsite. The system maximizes recycling of effluent back to the plant and minimizes the release of radioactive material to the environment by proper cleanup and volume reduction methods. The system process is a combination of degasification, demineralization, filtration, and evaporation. The boron recovery system is designed as NNS class and non-seismic Category I.

The boron recovery system is designed to do the following:

- process the reactor coolant letdown liquid generated by normal operations under either base loaded or load-following conditions
- permit startup from a cold shutdown condition (For conservatism, the plant is assumed to be in end-of-core-life conditions (50 parts per million (ppm) boron concentration), and evaporator availability is considered to be 75 percent of the time.)
- produce distillate from the boron evaporator with a maximum of 5 ppm boron and provide, by means of the boron demineralizers (mixed bed ion exchange units), the capability for reducing the boron concentration further, if so desired
- provide radioactivity decontamination and chemical purification such that, for reuse within the station, the system effluent meets the chemical purity requirements for recycled reactor makeup water and, for discharge from the station, the effluent meets required radioactivity release limitations
- accept and process any hydrogenated liquid drains collected in the primary drain tank

Other sources of liquid that can be transferred into the recovery test tanks (1-BRS-TK-58-A and 1-BRS-TK-58-B) include effluent from a skid-mounted waste liquid processing system should additional storage capacity be required prior to discharge.

2.3.3.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.2, UFSAR Section 9.3.5, 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. In addition to the continuation issue identified in RAI 2.3-01, as described in Section 2.3.3, the staff's review identified an area in which additional information was required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI, as discussed below.

In RAI 2.3.3.2-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-CS-LR20724, at location G-11, a section of safety-related 3 in. piping connected to nonsafety-related 3 in. piping at valve V-633. The piping section, located between valve V-633 and the seismic anchor located at G-9, is within the scope of license renewal for 10 CFR 54.4(a)(2). However, there is a 1 in. line that connects to the 3 in. nonsafety-related piping between valve V633 and the seismic anchor. This line continues and connects to a 3 in. piping section, which connects into a 3 in. line and $^{3}/_{4}$ in. line at location E-9. At location D-12 of LRA drawing PID-1-CS-LR20724, the 3 in. line continues through valves V-634, V-635, V-636 to a piping section that continues to LRA drawing PID-1-BRS-LR20856. This piping section is not depicted within the scope of license renewal. Additionally, at location D-12 of LRA drawing PID-1-CS-LR20724, the $^{3}/_{4}$ in. line continues through valve V-835 to LRA drawing PID-1-SS-LR20519. Seismic anchors could not be located between the start of the 1 in. line (at location G-9 on LRA drawing PID-1-CS-LR20724) and the 3 in. and $^{3}/_{4}$ in. continuations (at location D-12 on LRA drawing PID-1-CS-LR20724). The applicant was asked to provide the location of the first seismic anchors on nonsafety-related piping past the safety and nonsafety interface for the above locations.

In its response dated February 3, 2011, the applicant clarified why the seismic anchors were not depicted on the LRA drawings. The applicant described the pipe support anchors, 303-A-01 and 302-A-20, as being located beyond the safety and nonsafety interface to ensure that failure of the nonsafety-related piping does not affect the safety-related piping. The applicant also described the 302-A-20 anchor as being located at the tee intersection of the boron recovery system and chemical and volume control system (CS), which equally restrains the 1 in. piping. The applicant further indicated that the entire nonsafety-related piping is included within scope of license renewal and subject to AMR until the piping exits the primary auxiliary building and enters the waste process building, in which no seismic anchors are needed.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.2-01 acceptable because the staff confirmed that the description given in the applicant's RAI response is consistent with its scoping methodology in LRA Section 2.1.2.2.2 for nonsafety-related piping attached to safety-related piping. Therefore, the staff's concern described in RAI 2.3.3.2-01 is resolved.

2.3.3.2.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the boron recovery system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.3 Chemical and Volume Control System

2.3.3.3.1 Summary of Technical Information in the Application

The chemical and volume control system (CS) consists of the following subsystems:

- high-head injection part of the ECCS
- charging, letdown, and seal water system
- reactor coolant purification and chemistry control system
- reactor makeup control system

The CS is a support system for the RCS during all normal modes of plant operation. The centrifugal charging pumps serve as the high head SI pumps in the ECCS. The charging and letdown functions of the CS are employed to maintain a programmed level in the RCS pressurizer, thus maintaining proper reactor coolant inventory during all phases of plant operations. A portion of the charging flow is directed to the RCPs seals via a seal water injection filter. The reactor coolant purification and chemistry control system maintain reactor coolant chemistry within Electric Power Research Institute (EPRI) specified guidelines. The soluble neutron absorber (boric acid) concentration is controlled by the reactor makeup control system.

The CS consists of three charging pumps, a letdown heat exchanger, a regenerative heat exchanger, a volume control tank, and associated pumps, piping, valves, and filters. The CS also includes demineralizer vessels and chemical tanks associated with control of water chemistry in the RCS. The CS includes provisions for recycling reactor grade water and boric acid.

The intended functions of the CS component types within the scope of license renewal include the following:

- maintain the RCS pressure boundary
- maintain water inventory in the RCS
- vary boron concentration for reactivity control
- supply water to the RCP seals for cooling and sealing purposes
- provide containment isolation function
- provide high head SI for emergency core cooling

The following license renewal drawings provide the details of SSCs for the scope of license renewal and subject to an AMR:

- PID-1-BRS-LR20854
- PID-1-CS-LR20722–PID-1-CS-LR20729
- PID-1-CBS-LR20233
- PID-1-RH-LR20663
- PID-1-RC-LR20846
- PID-1-SI-LR20446–PID-1-SI-LR20449
- PID-1-RS-LR20252
- PID-1-SS-LR20519
- PID-1-WLD-LR20218
- PID-1-WLD-LR20223
- PID-1-CC-LR20212
- PID-1-RH-LR20662
- PID-1-RC-LR20841–PID-1-RC-LR20846
- PID-1-SF-LR20483
- PID-1-SS-LR20518
- PID-1-VSL-LR20775–PID-1-VSL-LR20777
- PID-1_WLD-LR20219
- PID-1-WLD-LR20222

LRA Table 2.3.3-3 lists the CS component types that require AMR.

2.3.3.3.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the CS component within the scope of license renewal, as required by

10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the CS component subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.4 Chlorination System

2.3.3.4.1 Summary of Technical Information in the Application

The chlorination (CL) system provides sodium hypochlorite solution for injection into the circulating water system. Provisions for continuous low-level CL and heat treatment of the tunnels are included for control of fouling by marine organisms.

Sodium hypochlorite is injected into a common header that receives flow from the screen wash system pumps. The flow from this common header flows to the following locations:

- intake tunnel
- intake transition structure
- discharge transition structure.
- circulating water pump bays
- service water pump bays

The CL system is nonsafety-related.

2.3.3.4.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the CL system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the CL system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.5 Containment Air Handling System

2.3.3.5.1 Summary of Technical Information in the Application

The containment air handling system is composed of three subsystems—the containment structure cooling system, the containment recirculation and filter system, and the CRDM cooling system.

The containment structure cooling system is designed to maintain the normal ambient air temperature in the containment structure at or below 120° F.

The containment recirculation and filter system is normally used to filter contaminated air within containment prior to personnel entry and whenever it is desired to reduce airborne particulate contamination and radioactive iodine. The filter subsystem, when operated in conjunction with the pre-entry purge subsystem, reduces the airborne iodine to an acceptable level, permitting access to containment within 24 hours after the reactor is shutdown. The fans, ductwork, and dampers associated with the containment recirculation subsystem are redundant, and, as such, a single failure will not render the system inoperative. Failure of the filter unit of the containment recirculation subsystem will not affect safe operation or shutdown of the plant since the air cleaning unit has no safety design bases.

The CRDM cooling system is designed to induce supply air into the CRDM shroud at or below 120° F.

2.3.3.5.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the containment air handling system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the containment air handling system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.6 Containment Air Purge System

2.3.3.6.1 Summary of Technical Information in the Application

The containment air purge system is composed of three subsystems—the containment structure air purge and heating subsystem, the pre-entry purge subsystem, and the refueling purge subsystem.

The containment air purge and heating subsystem employs two supply fans and two exhaust fans with the common supply and exhaust ductwork. Each set consists of a supply air fan and exhaust air fan, each with pneumatically operated dampers. A common ductwork system, which includes the refueling purge supply and heating subsystem and the pre-entry purge subsystem.

During pre-entry purge, a single fan supplies pre-entry purge air to the containment area using common supply ductwork. A single exhaust fan pulls air from containment through common exhaust ductwork and discharges directly to the unit plant vent after first passing through the filter unit and the containment air purge air cleaning unit.

In the refueling purge subsystem, a single fan supplies refueling purge and heating (when required) air to the containment area during the refueling operation using, as described above, the same ductwork as the pre-entry purge system. Dampers are used to isolate the non-operating system, in this case, the pre-entry purge. The 40,000 cubic feet per minute (cfm) exhaust airflow of the refueling purge subsystem first passes through a filter unit before discharging to the plant vent.

2.3.3.6.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the containment air purge system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the containment air purge system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.7 Containment Enclosure Air Handling System

2.3.3.7.1 Summary of Technical Information in the Application

The containment enclosure air handling system removes heat from areas associated with the containment enclosure, creates a negative pressure in the containment enclosure structure to capture post-accident leakage from the containment and contiguous areas, and filters the effluent prior to release from the plant vent. The containment enclosure and adjoining areas cooling systems are designed to remove equipment heat from the following areas during normal and emergency operation:

- charging pump areas
- SI pump areas
- RHR equipment areas
- containment spray pump and heat exchanger equipment areas
- mechanical penetration area
- containment enclosure ventilation equipment area
- H_2 analyzer room and electrical room areas
- RHR vault stairway area
- electrical tunnel personnel walkway (electrical) area

The containment enclosure cooling units maintain the first six areas (charging pump areas, SI pump areas, RHR equipment areas, containment spray pump and heat exchanger equipment areas, mechanical penetration area, containment enclosure ventilation equipment area, and H_2 analyzer room and electrical room areas) at, or below the safety-related equipment's maximum design operating temperatures during normal operation and following a LOCA, loss of offsite power, high and moderate pipe breaks, SSE, and tornados.

The H_2 analyzer and electrical room supply fans maintain area 7 at or below the safety-related equipment's maximum design operating temperatures during normal operation and following a LOCA, loss of offsite power, high and moderate pipe breaks, and an SSE.

The RHR vault stairway chilled water cooling units maintain area 8 at or below safety-related equipment's maximum design operating temperature during normal operation. This temperature is 104° F, coincident with an outside temperature of 88° F. The system provides auxiliary cooling to maintain area temperatures below 104° F. The cooling system is nonsafety-related and is operated, as required, to maintain the desired area temperature.

The electrical tunnel personnel walkway chilled water cooling units maintain area 9 at or below safety-related equipment's maximum design operating temperature during normal operation. This temperature is 104° F, coincident with an outside temperature of 88° F. The system provides auxiliary cooling to maintain area temperatures below 104° F. The cooling system is nonsafety-related and is operated, as required, to maintain the desired area temperature.

2.3.3.7.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the containment enclosure air handling system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the containment enclosure air handling system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.8 Containment Online Purge System

2.3.3.8.1 Summary of Technical Information in the Application

The containment online purge system provides supply air to the containment during normal operation and exhaust air from the containment to the plant vent filter. Valves in the exhaust line can be adjusted to establish containment pressure. The containment online purge subsystem supply air fan draws filtered, preheated air from the primary auxiliary building mechanical room at elevation 53 feet (ft) and distributes it through an 8 in. supply air duct into the containment.

The online purge subsystem exhaust equipment collects air from the containment and exhausts it to the normal exhaust filter unit located in the primary auxiliary building. This filtered air is then discharged to the plant vent. The purge exhaust valves are NNS-related, in accordance with ANSI B16.5.

2.3.3.8.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the containment online purge system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the containment online purge system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.9 Control Building Air Handling System

2.3.3.9.1 Summary of Technical Information in the Application

Seabrook's control room complex occupies the entire 75 ft elevation of the control building. The HVAC systems that service the control room complex are described below and in UFSAR Section 6.4, "Habitability Systems." In addition, the redundant filter systems integral to the emergency makeup air and filtration subsystem are detailed in the UFSAR. The control room complex HVAC system consists of the following subsystems:

- control room safety-related air conditioning subsystem
- control room nonsafety-related chilled water system
- computer room air conditioning subsystem
- control room normal makeup air subsystem
- control room emergency air makeup and filtration subsystem
- control room exhaust and static pressure control subsystem
- control room air conditioning subsystem

The control room air conditioning subsystem includes both safety-related and nonsafety-related cooling subsystems. The safety-related and nonsafety-related cooling subsystems share a common recirculating air system located on elevation 75 ft within the control room complex.

The safety-related control room air conditioning subsystem consists of two full-sized identical air cooling trains that are independently electrically powered. Each train consists of the following:

- a 100 percent capacity electric motor-driven water chiller
- two 100 percent capacity chilled water circulating pumps
- a 100 percent capacity chiller condenser exhaust fan
- a back draft damper
- a 100 percent capacity air handling unit located in the recirculated control room air cooling stream
- interconnecting piping, expansion tank, and I&Cs

2.3.3.9.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the control building air handling system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the control building air handling system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.10 Demineralized Water System

2.3.3.10.1 Summary of Technical Information in the Application

The demineralized water system serves no safety-related functions. It is designed as an NNS, non-seismic Category I system, except for the containment penetration piping and containment isolation valves, which are designed in accordance with safety Class 2, seismic Category I requirements. Additionally, the makeup water piping connections to the primary component cooling water head tanks are designed in accordance with safety Class 3, seismic Category I requirements. In addition, the interface piping with the condensate storage tank and the thermal barrier loop head pipe is safety Class 3.

The system is designed to provide a sufficient supply of demineralized water at a quality required for operation, makeup, and maintenance of the plant.

Water from the water treatment subsystem is directed to either a 500,000-gallon (gal.) or 200,000-gal. demineralized water storage tank. From here, the water can be transferred to the condensate storage tank or distributed throughout the unit by means of the demineralized water system. If the demineralized water storage tanks are full or not available, it is possible to bypass these tanks and go directly from the water treatment plant to the condensate storage tank. The demineralized water transfer subsystem supplies initial fill and makeup to the various services within the turbine, administration, containment, primary auxiliary, fuel storage, and waste processing buildings, as well as the condensate polishing facility. These services include reactor makeup, primary and secondary component cooling water, auxiliary boiler deaerator makeup, condensate polishing regeneration, emergency shower and eye wash stations, generator stator cooling, and maintenance flushing of systems and components located within the plant.

2.3.3.10.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the demineralized water system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the demineralized water system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.11 Dewatering System

2.3.3.11.1 Summary of Technical Information in the Application

Seabrook was not originally designed with a dewatering system because it was believed that the in-leakage prevention methods described in UFSAR Section 3.4.1.1, “Flood Protection Measures for Seismic Category I Structures,” would be adequate to prevent water ingress. Over the years, it has become evident that the mitigation methods were not completely effective at preventing in-leakage.

A plant dewatering system has been installed, which can further mitigate in-leakage of groundwater in the lower elevations of the plant. The purpose is to routinely pump water from beneath the plant structures, to reduce the static hydraulic head outside the building concrete, and to reduce the in-leakage. This allows the original mitigative measures to function properly. A pump is installed in the existing well at (+) 7 ft elevation of the primary auxiliary building. This pump discharges the water to the roof drains system, which then flows to the storm drain system and out to circulating water for discharge.

Existing pipe penetrations located in the (-) 26 ft elevation of the emergency feedwater pump house (EFPH) have been used as a groundwater low point. These penetrations have been directed to a nearby sump. This sump discharges to the existing plant storm drain system.

A pump is installed in the RHR vault “B” stairwell at (-) 61 ft elevation of the equipment vault. This pump discharges the water to the roof drains system, which then flows to the storm drain system and out to circulating water for discharge. Routine monitoring of this flow path is performed per station operating procedures.

A pump is installed in the containment annulus at (–) 32 ft elevation. This pump discharges the ground water in the containment annulus to the roof drain system. The connection to the drain system is installed at 240 degrees azimuth of the containment annulus. Routine monitoring of this flow path is performed per station operating procedures.

A ground water collection tank and pump are installed in the “B” electrical tunnel, west stairwell at (-) 20 ft elevation. The pump discharges the water to the turbine building roof drains system, which then flows to the storm drain system and out to circulating water for discharge via the outfall. Routine monitoring of this flow path is performed per station operating procedure.

2.3.3.11.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the dewatering system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the dewatering system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.12 Diesel Generator

2.3.3.12.1 Summary of Technical Information in the Application

The standby power supply is provided by two redundant diesel engine generators of identical design and characteristics, which supply onsite power of sufficient capacity and capability to reliably shut down the reactor. The diesel generator system includes the skid mounted diesel generators and their auxiliaries.

2.3.3.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.12; UFSAR Section 8.3, Section 9.5, and Table 7.5-1; 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 required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI, as discussed below.

In RAI 2.3.3.12-01, dated January 5, 2011, the staff noted on LRA drawings PID-1-DG-LR20460 and PID-1-DG-LR20465, at location F-10, a pulsation damper and cooling pipe within the scope of license renewal under 10 CFR 54.4(a)(1). The same LRA drawings, at location B-7, depict upper and lower bearing gear interlock components within the scope of license renewal under 10 CFR 54.4(a)(1). However, none of the above components were included in LRA Table 2.3.3-12. The applicant was asked to justify the exclusion of these components from LRA Table 2.3.3-12.

In its response dated February 3, 2011, the applicant indicated that the pulsation damper and cooling pipe components are in-scope for license renewal and were grouped under component type "piping and fittings" in Table 2.3.3-12. The applicant also stated that the upper and lower bearing gear interlock components were also in-scope for license renewal and were grouped under component type "valve body" in Table 2.3.3-12.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.12-01 acceptable because the staff confirmed that the component types, "piping and fittings" and "valve body," are included on LRA Table 2.3.3-12. Therefore, the staff's concern described in RAI 2.3.3.12-01 is resolved.

2.3.3.12.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the diesel generator system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.13 Diesel Generator Air Handling System

2.3.3.13.1 Summary of Technical Information in the Application

The diesel generator building heating and ventilating system removes heat generated in the building during normal and emergency conditions and maintains the design winter indoor building temperature. Ventilation is provided by the diesel generator air handling system. Electric heaters provided in each day tank room are included in the diesel generator air handling system. The remainder of the diesel generator building heating function is provided by the HW and is evaluated separately.

2.3.3.13.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the diesel generator air handling system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the diesel generator air handling system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.14 Emergency Feedwater Pump House Air Handling System

2.3.3.14.1 Summary of Technical Information in the Application

The function of the heating and ventilating systems is to maintain the inside temperature of the emergency feedwater pump house within design limits for both normal and emergency feedwater system operation during summer and winter.

The ventilation function is provided by the EPA system. The heating function is provided by the HW system and is evaluated separately.

The emergency feedwater pump house is ventilated and cooled with outside air, supplied through one of the two redundant supply fans and its tornado gravity intake damper with pneumatic test operator and exhausted through its tornado exhaust damper with pneumatic operator. Each fan and its exhaust damper are controlled by a separate room thermostat. Setpoints are staggered to avoid simultaneous operation of redundant equipment. The emergency feedwater pump house high temperature is alarmed.

The redundant, seismic Category I, safety Class 3, pump room supply fans, supply and exhaust dampers, and the Class 1E fan motors, each with electrical power from a separate engineered safety features power source, assure continued ventilation should an SSE, loss of offsite power, or single failure occur. Loss of air or electrical power to the pneumatically-operated supply and exhaust dampers will cause them to fail open.

2.3.3.14.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the EPA system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the EPA system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.15 Fire Protection System

2.3.3.15.1 Summary of Technical Information in the Application

The fire protection system is a nonsafety-related system designed to detect and alarm, control, and extinguish fires that may occur. To accomplish this end, the concept of defense in depth is a criterion for design. This concept, applied to fire protection, aims at a balanced program, which will do the following:

- prevent fires from starting
- detect fires quickly and quickly suppress those that occur, thus limiting their damage
- design and locate plant equipment such that, if a fire occurs and burns for a long time, essential plant activities will still be performed
- ensure that neither inadvertent operation nor failure of a fire protection system will induce a failure of any safety-related system

LRA Section 2.3.3.15 describes the fire protection systems. LRA Table 2.3.3-15 identifies the component types within the scope of license renewal and subject to an AMR.

The fire protection system includes nonsafety-related components that are attached to or located near safety-related SSCs, whose failure creates a potential for spatial interaction that could prevent the satisfactory accomplishment of a function identified in 10 CFR 54.4(a)(1). Therefore, the fire protection system satisfies the scoping criteria of 10 CFR 54.4(a)(2). The fire protection system is relied upon to demonstrate compliance with, and satisfies the 10 CFR 54.4(a)(3) scoping criteria for, the fire protection (10 CFR 50.48) regulated event.

2.3.3.15.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.15, the UFSAR, and LRA drawings using the evaluation methodology described in SER Section 2.3 and guidance in SRP-LR, Section 2.3. The staff also reviewed UFSAR Section 9.5.1, "Fire Protection System," and Fire Protection Evaluation and Comparison to Branch Technical Position (BTP) APCSB 9.5-1, Appendix A Report (i.e., approved fire protection program, a point-by-point comparison with Appendix A) to the BTP, APCSB 9.5-1, “Guidelines for Fire Protection for Nuclear Power Plants,” May 1, 1976.

The staff also reviewed the following fire protection documents, cited in the CLB, listed in the Seabrook Operating License Condition 2.F:

- NUREG-0896, “Safety Evaluation Report related to the operation of Seabrook Station, Units 1 and 2,” dated March 1983
- NUREG-0896, “Safety Evaluation Report related to the operation of Seabrook Station, Units 1 and 2,” Supplement 4, dated May 1986
- NUREG-0896, “Safety Evaluation Report related to the operation of Seabrook Station, Units 1 and 2,” Supplement 5, dated July 1986
- NUREG-0896, “Safety Evaluation Report related to the operation of Seabrook Station, Units 1 and 2,” Supplement 6, dated October 1986
- NUREG-0896, “Safety Evaluation Report related to the operation of Seabrook Station, Units 1 and 2,” Supplement 7, dated October 1987
- NUREG-0896, “Safety Evaluation Report related to the operation of Seabrook Station, Units 1 and 2,” Supplement 8, dated May 1989

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 pursuant to 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that the applicant had not omitted any passive or long-lived components subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

During its review of LRA Section 2.3.3.15, the staff identified areas in which additional information was necessary to complete its review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.15-1, dated November 18, 2010, the staff stated that LRA drawing PID-1-FP-LR20270 shows that sprinkler systems at locations C-4 to H-4 are out of scope (i.e., not colored in red). The staff requested that the applicant verify if these sprinkler systems, installed in various areas of the plant, are 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). If they are excluded from the scope of license renewal and not subject to an AMR, the staff asked that the applicant justify the exclusion.

In a letter dated December 3, 2010, the applicant responded to RAI 2.3.3.15-1 by stating the following:

> The sprinkler systems located on drawing PID-1-FP-LR20270, locations C-4 to H-4, are not in scope of License Renewal because they do not provide a function credited in Appendix R safe shutdown analysis and do not provide a pressure boundary function needed to support the Appendix R suppression systems. All other sprinklers located in the turbine building are in scope because they perform a pressure boundary function necessary to permit the required Appendix R fire suppression systems to function properly.

In evaluating this response, the staff found that it was inadequate, and review of LRA Section 2.3.3.15 could not be completed. The applicant's response to RAI 2.3.3.15-1 was inconsistent with the UFSAR Revision 13, Section 9.5.1.2(c)(7), "Manually Operated Pre-Action Sprinkler Systems," which states that manually-operated sprinkler systems are provided for areas containing turbine bearings and lube oil piping from turbine bearings to guard. Therefore, by letter to the applicant dated March 30, 2011, the staff issued a followup RAI concerning the specific issues to determine if the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1).

In the followup RAI, the staff stated that the fire suppression systems discussed above appeared to be credited in the approved Fire Protection Program (UFSAR Section 9.5.1) for fire suppression activities. The staff explained that the applicant's analysis of fire protection regulations does not completely capture the fire protection SSCs required for compliance with 10 CFR 50.48. The scope of fire protection SSCs, required for compliance with 10 CFR 50.48 and General Design Criterion (GDC) 3, goes beyond preserving the ability to maintain safe-shutdown in the event of a fire. The staff stated that the exclusion of fire protection SSCs, on the basis that the intended function is not required for the protection of safe-shutdown equipment or safety-related equipment, is not acceptable if the fire protection SSC is required for compliance with 10 CFR 50.48.

In its response, dated April 22, 2011, the applicant stated that the sprinkler systems downstream of valves 1-FP-V-792 and 1-FP-V-800 at locations C-4 to H-4 on boundary drawing PID-1-FP-LR20270 have been added to the license renewal, and the LRA has been revised.

Based on its review, the staff finds the applicant's response to the followup RAI acceptable because it indicated that the sprinkler system in question is within the scope of license renewal and subject to an AMR. The staff's concern described in RAI 2.3.3.15-1 is resolved.

In RAI 2.3.3.15-2, dated November 18, 2010, the staff stated that LRA drawing PID-1-FP-LR20274 shows that several yard fire hydrants and post-indicator valves are out of scope (i.e., not colored in red). The staff believed that yard fire hydrants and post-indicator valves have the fire protection-intended functions required to be compliant with 10 CFR 50.48, as stated in 10 CFR 54.4. The fire hydrants and post-indicator valves also serve as the pressure boundary for the fire protection water supply system. Further, NUREG-0896, "Safety Evaluation Report related to the operation of Seabrook Station, Units 1 and 2," dated March 1983, Section 9.5.1.5, "Fire Detection and Suppression," on page 9-47, states that "…[y]ard hydrants are provided at intervals of 250 ft along the fire protection water supply loop, approximately 40 ft from the buildings…Each yard hydrant is provided with an isolation valve to facilitate hydrant maintenance and repairs without shutting down any part of the fire water supply system…"

The staff requested that the applicant verify if the yard hydrants and post-indicator valves are in the scope of license renewal, in accordance with 10 CFR 54.4(a), and if they are subject to an AMR, in accordance with 10 CFR 54.21(a)(1). If they are excluded from the scope of license renewal and are not subject to an AMR, the staff requested that the applicant justify the exclusion.

In a letter dated December 3, 2010, the applicant responded to RAI 2.3.3.15-2 by stating the following:

> The yard fire hydrants required to support Unit 1 compliance with 10 CFR 50.48 and Appendix R safe shutdown are included in scope of License Renewal (See PID-1-FP-LR20274 demarcation line) and are subject to an AMR in accordance with 10 CFR 54.21 (a)(1). The yard fire hydrants supporting Unit 2 and the site support buildings are not required for compliance with 10 CFR 50.48 and Appendix R safe shutdown and do not have a License Renewal-intended function and are not in scope of license renewal. Construction on Seabrook Station Unit 2 was effectively terminated in 1984 and its construction permit was allowed to expire in October 1988. All of the post indicator valves located on the fire main ring header and any branch header isolation post indicator valves are in scope of License Renewal and are subject to an AMR in accordance with 10 CFR 54.21 (a)(1). All other post indicating valves that supply support buildings and branch headers are not required for compliance with 10 CFR 50.48 or Appendix R safe shutdown and do not have a License Renewal-intended function and are not in scope of license renewal.

The staff reviewed the applicant's response to RAI 2.3.3.15-2, which confirmed that the yard fire hydrants and post-indicator valves in question are associated with Seabrook Unit 2 (Seabrook Unit 2 construction was terminated in 1984 and its construction permit expired in October 1988). They are not required for Unit 1 compliance with 10 CFR 50.48 and Appendix R safe shutdown, and they do not have a license renewal-intended function and are not within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.15-2 is resolved.

In RAI 2.3.3.15-3, dated November 18, 2010, the staff stated that Section 9.5.1.6, "Fire Protection of Specific Plant Areas," of NUREG-0896, "Safety Evaluation Report related to the operation of Seabrook Station, Units 1 and 2," dated March 1983, on page 9-48, states that "…the applicant committed to provide oil collection systems for each RCP in accordance with Section III.O Appendix R…" LRA Section 2.3.3.15 did not discuss scoping and screening results of RCP oil collection systems and their associated components.

The staff requested that the applicant verify if the RCP oil collection systems and their associated components are 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). If RCP oil collection systems and their associated components are excluded from the scope of license renewal and not subject to an AMR, the staff requested that the applicant justify the exclusion.

In a letter dated December 3, 2010, the applicant responded to RAI 2.3.3.15-3 by stating the following:

> The Reactor Coolant Oil collection system is in scope for fire protection (10 CFR 54.4 (a)(3)) and is subject to an AMR in accordance with 10 CFR 54.21(a)(1). See LRA Section 2.3.3.25, "Oil Collection for Reactor Coolant Pumps System;" on page 2.3-189.

The staff reviewed the applicant's response to RAI 2.3.3.15-3, including verification of the referenced discussion on LRA page 2.3-189, which confirmed that the RCP oil collection systems and their associated components have been included in the scope of license renewal and are subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.15-3 is resolved.

In RAI 2.3.3.15-4, dated November 18, 2010, the staff stated that Section 9.5.1.6, "Fire Protection of Specific Plant Areas," of NUREG-0896, "Safety Evaluation Report related to the operation of Seabrook Station, Units 1 and 2," dated March 1983, on page 9-52, "Cable Spreading Room," states that "…[a] manual smoke ventilation system has been provided to exhaust the cable spreading room in the event of a fire…" LRA Section 2.3.3.15 did not discuss scoping and screening results of the cable spreading room (CSR) manual smoke ventilation system and its associated components.

The staff requested that the applicant verify if the CSR manual smoke ventilation system and its associated components are 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). If the CSR manual smoke ventilation system and its associated components are excluded from the scope of license renewal and not subject to an AMR, the staff requested that the applicant justify the exclusion.

In a letter dated December 3, 2010, the applicant responded to RAI 2.3.3.15-4 by stating the following:

> The manual smoke removal system is not in scope of License Renewal. The fans (1-CBA-FN-17 and 1 -CBA-FN-18) used for smoke removal are not credited for safe shutdown by UFSAR…for a fire in the Cable Spreading Room or any other Appendix R fire. There are no manual safe shutdown actions requiring access to this area. The fans are not safety related, are not credited for Appendix R safe shutdown and therefore have no License Renewal function (refer to PID-1-CBA-LR20303 location G-5 and H-5).

> USFAR Section 9.4.9.1 provides a description of the cable spreading room ventilation.

Based on its review, the staff finds the applicant's response acceptable because the manual smoke ventilation system in question is not in-scope for license renewal and is not credited with achieving safe-shutdown in the event of a fire. Although the CSR smoke ventilation system is addressed in NUREG-0896, the system in question is not required in Appendix R for achieving safe-shutdown in the event of a fire.

In the original SER, NUREG-0896, NRC reviewed the CSR smoke ventilation system because the licensee provided system description in the incoming UFSAR, but the licensee has not credited this system in the fire protection program. The manual smoke removal system in question is for loss of prevention purposes only.

The staff confirmed that the applicant correctly excluded the above smoke ventilation system from scope of license renewal and subject to an AMR. Therefore, the staff's concern described in the RAI 2.3.3.15-4 is resolved.

In RAI 2.3.3.15-5, dated November 18, 2010, the staff stated that Section 9.5.1.6, "Fire Protection of Specific Plant Areas," of the Seabrook SER (NUREG-0896), dated March 1983, on page 9-53, "Switchgear Rooms," states that "…[t]he Division I and Division II switchgear rooms are separated from each other and from other plant areas by 3-hour-fire-rated wall and floor/ceiling assemblies. Automatic fire detection is provided by ionization smoke detectors. Manual protection is provided by standpipe and hose stations and portable extinguishers…" LRA Section 2.3.3.15 did not discuss scoping and screening results of Division I and Division II switchgear rooms' standpipe and hose stations.

The staff requested that the applicant verify if the Division I and Division II switchgear rooms' standpipe and hose stations are 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). If the Division I and Division II switchgear rooms' standpipe and hose stations are excluded from the scope of license renewal and not subject to an AMR, the staff requested that the applicant justify the exclusion.

In a letter dated December 3, 2010, the applicant responded to RAI 2.3.3.15-5 by stating the following:

> The standpipes and valves for the hose stations for extinguishing a fire in the Division I and Division II switchgear rooms are in scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The switch gear rooms do not contain any fire protection piping. The hose stations referred to are located in the turbine building (see PID-1-FP-LR20270 Location E-12-1-FP-R-8-A) and the south stairwell of the control building (see PID-1-FP-LR20268 Location F-7 for 1-FP-R-30).
>
> The hose stations reels and hoses for 1-FP-R-8-A and 1-FP-R-30 are in scope for license renewal. The reels are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The fire hoses are classified as consumables and are replaced on condition, as described on page 2.1-24 of the LRA.

Based on its review, the staff finds the applicant's response, as clarified to include verification of the referenced discussion on page 2.1-24 of the LRA, acceptable because it indicated that the standpipe and hose stations in question have been included in the scope of license renewal and are subject to an AMR. Further, the applicant indicated that the fire hoses are classified as consumables and are replaced on condition. Therefore, the staff's concern described in RAI 2.3.3.15-5 is resolved.

In RAI 2.3.3.15-6, dated November 18, 2010, the staff stated that Section 9.5.1.6, "Fire Protection of Specific Plant Areas," of the Seabrook SER (NUREG-0896), dated March 1983, on page 9-53, "Safety-Related Battery Rooms," states that "…[h]ose stations and portable fire extinguishers are available in the areas for fire manual suppression…" LRA Section 2.3.3.15 did not discuss scoping and screening results of safety-related battery rooms' hose stations.

The staff requested that the applicant verify if the safety-related battery rooms' hose stations are 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). If safety-related battery rooms' hose stations are excluded from the scope of license renewal and not subject to an AMR, the staff requested that the applicant justify the exclusion.

In a letter dated December 3, 2010, the applicant responded to RAI 2.3.3.15-6 by stating the following:

> The standpipes and valves for the hose stations for the safety related battery rooms are in scope of license renewal and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The battery rooms do not contain any fire protection piping. The hose stations referred to are located in the turbine building (see PID-1-FP-LR20270 Location E-12 1-FP-R-8-A) and the south stairwell of the control building (see PID-1-FP-LR20268 Location F-7 for 1-FP-R-30).
>
> The hose stations reels and hoses for 1-FP-R-8-A and 1-FP-R-30 are in scope for license renewal. The reels are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The fire hoses are classified as consumables and are replaced on condition, as described on page 2.1-24 of the LRA.

The staff reviewed the applicant's response to RAI 2.3.3.15-6, including verification of the referenced discussion on page 2.1-24, which confirmed that the standpipe and hose stations in question have been included in the scope of license renewal and are subject to an AMR. Further, the applicant indicated that the fire hoses are classified as consumables and are replaced on condition. Therefore, the staff's concern described in RAI 2.3.3.15-6 is resolved.

In RAI 2.3.3.15-7, dated November 18, 2010, the staff stated that Section 9.5.1.6, "Fire Protection of Specific Plant Areas," of the Seabrook SER (NUREG-0896), dated March 1983, on page 9-53, "Emergency Diesel Generator Rooms," states that "…[t]he floor trench containing fuel oil piping in each diesel generator room is provided with an automatic deluge system to combat a fire in the trench." LRA Section 2.3.3.15 did not discuss scoping and screening results of the automatic deluge system in the diesel generator room floor trench containing fuel oil piping.

The staff requested that the applicant verify if the automatic deluge system in question is 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). If the automatic deluge system is excluded from the scope of license renewal and not subject to an AMR, the staff requested that the applicant justify the exclusion.

In a letter dated December 3, 2010, the applicant responded to RAI 2.3.3.15-7 by stating the following:

> The floor trench containing fuel oil piping in each diesel generator room with an automatic deluge system is in scope of license renewal and is subject to an AMR in accordance with 10 CFR 54.21 (a)(1). See LRA Page 2.3-148 (for the in scope boundary description) and PID-1-FP-LR20271 location H-10 and F-10 for sprinkler zones 1A-2 and 1B-2.

The staff reviewed the applicant response to RAI 2.3.3.15-7, including verification of the referenced discussion on page 2.3-148, which confirmed that the automatic deluge system associated with diesel generator rooms floor trench containing fuel oil piping has been included in the scope of license renewal and is subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.15-7 is resolved.

In RAI 2.3.3.15-8, dated November 18, 2010, the staff stated that Tables 2.3.3-22 and 3.3.2-22 of the LRA do not include the following fire protection components:

- fire hose stations, fire hose connections, and hose racks
- yard fire hydrants
- strainers
- tubing
- spray nozzles
- diesel fire pump engine—heat exchanger bonnet, shell, tubes, and exhaust silencer
- floor drains for fire water
- dikes and curbs for oil spill confinement

The staff requested that the applicant verify if the fire protection components listed above are 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). If they are excluded from the scope of license renewal and are not subject to an AMR, the staff requested that the applicant justify the exclusion.

In a letter dated December 3, 2010, the applicant responded to RAI 2.3.3.15-8 by stating the following:

> License renewal drawing (PID [license renewal] Notes 1) provides a description of the component types and a correlation that shows the component grouping they are evaluated as.
>
> Fire protection system components subject to age management review are listed in Table 2.3.3-15 (page 2.3-151) and a summary of the aging management evaluation for the fire protection system is provided in Table 3.3.2-15 (page 3.3-300) of the LRA. Fire hose stations include the fire hose, the fire hose racks (evaluated as supports) and the fire hose connections.
>
> - The fire hose racks (supports) are evaluated under supports in the LRA Section 2.4.6 and are in scope of License Renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1).
> - Fire hoses are within the scope of License Renewal, but are not subject to aging management because they are replaced based on condition. These components are periodically inspected in accordance with National

Fire Protection Association (NFPA) standards. Fire hoses are considered consumables. See section 2.3.1 (page 2.1-24) in the LRA.

- Fire hose connections are in scope of license renewal and are evaluated as pipe and fittings and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). See Table 3.3.2-15 (page 3.3-300) in the LRA.
- Yard fire hydrants in the scope of License Renewal are designated FH on the license renewal prints and are evaluated as valves in Table 3.3.2-15 on page 3.3-300 of the LRA and are subject to an AMR in accordance with 10 CFR 54.21(a)(1).
- Strainers in scope of License Renewal are evaluated as filter elements and filter housings in Table 3.3.2-15 on page 3.3-300 of the LRA and are subject to an AMR in accordance with 10 CFR 54.21(a)(1).
- Tubing in scope of License Renewal is evaluated as pipe in Table 3.3.2-15 (page 3.3-300) of the LRA and is subject to an AMR in accordance with 10 CFR 54.21(a)(1).
- Spray nozzles in the scope of License Renewal are evaluated as sprinklers in Table 3.3.2-15 (page 3.3-300) of the LRA and are subject to an AMR in accordance with 10 CFR 54.21(a)(1).
- The diesel fire pump engine heat exchanger including the bonnet, shell, and tubes, are an integral part of the diesel fire pump engine and were evaluated as a unit. The diesel fire pump engine is screened out as an active component per NEI 95-10 Appendix B.
- The diesel fire pump exhaust silencer is evaluated under pipe and fittings and is subject to an AMR in accordance with 10 CFR 54.21(a)(1). See Table 3.3.2-15 (pages 3.3-308 and 309). The summary of the aging management review for the internal surface is provided on page 3.3-309, Piping and Fittings, Pressure Boundary, Steel, Diesel Exhaust (Internal). The summary of the aging management review for the external surface is provided on page 3.3-308, Piping and Fittings.
- Floor drains for fire water are in scope of License Renewal and evaluated in section 2.3.3.45, “Waste Processing Liquid Drains System," (page 2.3-269) and section 2.3.3.26, “Plant Floor Drain System,” (page 2.3-191) of the LRA. These floor drains are subject to an AMR in accordance with 10 CFR 54.21(a)(1).
- The dikes and curbs' for oil spill confinement in scope of License Renewal are evaluated under structures as a commodity under Concrete in Tables 3.5.2-2 and 3.5.2-5. These dikes and curbs are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In reviewing its response to RAI 2.2.3.15-8, the staff found that the applicant had addressed and resolved each item in the RAI, as discussed below.

Fire hose stations, including fire hose racks and fire hose connections, are in the scope of license renewal and subject to an AMR. Fire hose racks are included under line item “Supports,” which are in the scope of license renewal, subject to an AMR, and listed in LRA Section 2.4.6. Fire hose connections are evaluated under line item description “Piping and

Fitting," in LRA Table 3.3.2-15. Fire hoses are within the scope of license renewal, but are not subject to an AMR because they are consumable. The applicant stated that it considers yard fire hydrants in the line item "Valves," in Table 3.3.2-15, and they are subject to an AMR.

Tubing is also evaluated under line item description "Piping and Fitting," in LRA Table 3.3.2-15. In addition, the applicant addressed strainers under line items "Filter Elements," and "Filter Housings," in LRA Table 3.3.2-15. Furthermore, in its response, the applicant confirmed that spray nozzles are included under line item "Sprinklers," which are in the scope of license renewal, subject to an AMR, and listed in Table 3.3.2-15.

The applicant stated that fire pump exhaust silencer is evaluated under line item description "Piping and Fitting," in LRA Table 3.3.2-15. Further, the applicant considered heat exchanger bonnet, shell, and tubes to be active components as a part diesel fire pump engine; they are not subject to an AMR.

The floor drains for fire water are included under "Plant Floor Drain System" in LRA Section 2.3.3.26 and "Waste Processing Liquid Drains System" in Section 2.3.3.45; these are in the scope of license renewal and subject to an AMR. The applicant considered curbs for oil spill confinement under structural commodities as "Concrete," listed in LRA Tables 3.5.2-2 and 3.5.2-5.

2.3.3.15.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant 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 all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.16 Fuel Handling System

2.3.3.16.1 Summary of Technical Information in the Application

The new fuel storage facilities are located within the fuel storage building and are designed to facilitate the safe handling, inspection, and storage of new fuel assemblies and control rods. Space is provided for handling and storage of 90 new fuel assemblies, which is equal to a core load plus 25 spare assemblies.

The fuel transfer system includes an underwater, electric-motor-driven, transfer car that runs on tracks extending from the containment refueling canal through the transfer tube and into the fuel storage building refueling canal. A hydraulically actuated lifting arm is on each end of the transfer tube. The fuel container in the refueling canal receives a fuel assembly in the vertical position from the refueling machine. The fuel assembly is then lowered to a horizontal position for passage through the transfer tube. After passing through the tube, the fuel assembly is raised to a vertical position for removal by a tool suspended from the spent fuel pool bridge and hoist in the fuel storage building refueling canal. A system of lifting arms and hydraulic cylinders is used to raise and lower the fuel containers containing the fuel assembly. The cylinders are powered by hydraulic pumping units and controlled by electronic consoles. The pumping units and consoles (one each in the containment and fuel storage building, designated 1-FH-RE-44 and 1-FH-RE-45, respectively) are located on the operating deck of each building. The spent fuel pool bridge and hoist then moves to a storage loading position and places the spent fuel assembly in the spent fuel storage racks.

During reactor operation, the transfer car is stored in the fuel storage building refueling canal. The quick closure hatch is engaged closed on the containment refueling canal end of the transfer tube to seal the reactor containment. The terminus of the tube in the fuel storage building is closed by a valve.

2.3.3.16.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the fuel handling system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the fuel handling system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.17 Fuel Oil System

2.3.3.17.1 Summary of Technical Information in the Application

The fuel oil system provides fuel to the two diesel driven fire pumps—1-FPP-20A and 1-FPP-20B. There are two fuel tanks, each dedicated to a diesel driven fire pump.

2.3.3.17.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the fuel oil system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the fuel oil system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.18 Fuel Storage Building Air Handling System

2.3.3.18.1 Summary of Technical Information in the Application

The normal heating and ventilation subsystem is comprised of filters, dual purpose chilled water cooling and hot water heating coils for summer cooling or winter heating, supply air fans, chillers, and a ducted distribution system with parallel-path supply dampers, which are a part of the primary auxiliary building ventilation system. A hot water unit heater system, which is supplied with hot water from the primary auxiliary building HW system, is also provided. The system is designed to maintain inside design temperatures suitable for equipment and personnel.

The ventilation function is provided by the fuel storage building ventilation system. The heating function is provided by the HW system and is evaluated separately.

The normal heating and ventilation subsystem employs two slotted exhaust intake hoods designed to sweep the pool surface in order to capture the dilute vapors emanating from the spent fuel pool. The entrained air and vapor are ducted to a vane axial fan, normal ventilation exhaust air isolation damper and from there to the unit plant vent.

Two basic modes of air handling are available, as discussed below. For all modes, the operation of the mechanical equipment is controlled and monitored from the plant unit control room.

Normal Once-Through Supply Exhaust Ventilation Mode. During normal operation, filtered outside air is circulated through the fuel storage building by the normal ventilation system, with the exhaust air discharged from the building via the unit plant vent. Filtering of the exhaust air is not normally performed.

Fuel Handling Mode. The fuel handling mode is used any time irradiated fuel not in a sealed cask is handled. In the fuel handling mode of operation, the normal building exhaust system is isolated prior to initiation of fuel handling operations by closing the normal exhaust isolation damper and stopping the normal exhaust fan. The fuel storage building is maintained at a negative pressure of 0.25 in. water gauge (w.g.) or more (negative). This is achieved by exhausting air from the building at a higher rate than directly supplied from the primary auxiliary building supply air system. Maintaining the building at a negative pressure will minimize, or eliminate, the leakage of radioactive material to the environment in the event of an accident. The exhaust filter trains are redundant, with one unit required to operate in the event of an accident.

The redundant filter units and their respective components are fed from independent power sources so that no single failure would prevent the obtaining and maintaining of the negative pressure. The static pressure control for the parallel supply system dampers are provided with manual override provisions to allow the operator to control the damper position and the building pressure if required.

The fuel storage building emergency air cleaning system is a seismic Category I, safety Class 3 system.

2.3.3.18.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the fuel storage building air handling system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the fuel storage building air handling system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.19 Hot Water Heating System

2.3.3.19.1 Summary of Technical Information in the Application

The hot water heating (HW) system includes the station designated hot water supply and hot water return systems. In addition to providing heating to buildings not within the license renewal boundary, such as the administration building, turbine building and waste process building, the HW provides the functions described below.

Fuel storage building normal heating is comprised of filters, dual purpose chilled water cooling and hot water heating coils for summer cooling or winter heating, supply air fans, chillers, and a ducted distribution system with parallel path supply dampers, which are a part of the primary auxiliary building ventilation system. A hot water unit heater system, which is supplied with hot water from the primary auxiliary building HW system, is also provided. The system is designed to maintain inside design temperatures suitable for equipment and personnel.

Primary auxiliary building heating is maintained in the winter by heating the outside air with a bank of dual purpose chilled water cooling and hot water heating coils. The water temperature for the main hot water heating coils is controlled by thermostats mounted in the primary auxiliary building. The heating coils are supplied with hot water and glycol from a closed loop parallel pump circulating system using a common steam and hot water converter. The closed loop circulating system for the main heating coils is comprised of three pumps, one for each bank of heating coils and one reserve pump, each manually controlled locally. Each pump once started runs continuously. Certain rooms contain a pair, or pairs, of unit heaters connected to thermostats located in the room that will operate the unit heater fans to maintain the room temperature above minimum design requirements. The unit heaters are supplied with hot water and glycol from a closed loop system using the same steam and hot water converter as the primary auxiliary building main hot water heating coils. One centrifugal pump provides circulating water to all of the unit heaters within each room. The pump is started manually from the main control panel and runs continuously.

Heating for the diesel generator building is provided by hot water unit heaters. Four unit heaters are located in each diesel generator area. Each of the two area heating systems is provided with hot water from the hot water and steam converter. Three hot water circulating pumps, one for each area and the third, a standby for both, are energized from the local control panel and will run until the operator manually stops them. Operation of the unit heaters is thermostatically controlled. The hot water heating piping is contained or shielded where it passes over safety-related electrical equipment. Cable speading room ventilation system supply air is reheated, when required, by a hot water heating coil in the supply ductwork to offset building heat losses. The cable spreading room ventilating system obtains makeup air and hot water for heating from the switchgear area and battery rooms heating and ventilating system.

In the winter the 4-kilovolt (kV) switchgear areas, cable spreading area, and the electrical tunnel area air is recirculated and mixed with preheated outside air, as necessary, for makeup and to maintain the inside design temperature. The 4-kV switchgear areas and battery rooms have two ventilation equipment rooms, one for each train. The equipment rooms serve as a return air and makeup air mixing plenum. The heat required to offset building heat loss from the switchgear areas, battery rooms, and electrical tunnels is supplied by hot water unit heaters located in the equipment rooms. Water line breaks or hot water system failures will not affect the operation of the switchgear areas or battery rooms.

The emergency feedwater water pump house heating system is designed to maintain the pump house at or above 50° F when the outside temperature is 0° F or above. The heating system consists of a shared steam and hot water converter, two 100 percent capacity pumps, a piping system, and two 100 percent capacity unit heaters. The heating medium is a mixture of water and glycol in a closed loop circulating system. The glycol acts to prevent freezing should the steam supply, electrical power source, or a pump or driver fail. Each unit heater is controlled by its own room thermostat.

The pump room area of the service water pump house is maintained at 50° F or above when the outside temperature is 0° F or above by a HW system using unit heaters. Hot water is pumped through the unit heaters from a steam-to-hot-water heat exchanger located in the adjacent circulating water pump house. The heating system is not required to maintain operation of the service water pumping equipment.

2.3.3.19.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.19, UFSAR Section 9.4, 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 required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.19-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-HW-LR20051 that the applicant depicts the HW expansion tanks within the scope of license renewal under 10 CFR 54.4(a)(2). The $^1/_2$ in. vent lines attached to the expansion tanks, at locations G-11 and G-12, are shown not within scope of license renewal. The applicant was asked to justify the exclusion of the $^1/_2$ in. vent lines from scope of license renewal.

In its response dated February 3, 2011, the applicant clarified that the $^1/_2$ in. vent lines are within the scope of license renewal for 10 CFR 54.4(a)(2). The applicant also described the $^1/_2$ in. vent lines as $^1/_2$ in. carbon steel piping with threaded plugs at the end.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.19-01 acceptable because the staff confirmed that the $^1/_2$ in. vent lines are already included within the scope of license renewal under 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.3.19-01 is resolved.

In RAI 2.3.3.19-02, dated January 5, 2011, the staff noted on LRA drawing PID-1-HW-LR20056, at location G-11, that the applicant depicted the make-up tank as not being within the scope of license renewal. However, the make-up tank is connected to nonsafety-related piping that is included within the scope of license renewal under 10 CFR 54.4(a)(2). The applicant was asked to justify its exclusion of the make-up tank from the scope of license renewal.

In its response dated February 3, 2011, the applicant stated that the make-up tank is within scope of license renewal under 10 CFR 54.4(a)(2). The applicant indicated that the LRA drawing PID-1-HW-LR20056 erroneously depicted the make-up tank excluded from scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.19-02 acceptable because the applicant clarified that the make-up tank is within the scope of license renewal under 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.3.19-02 is resolved.

2.3.3.19.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the HW system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.20 Instrument Air System

2.3.3.20.1 Summary of Technical Information in the Application

The plant's compressed air function is provided by the service air and the instrument air systems. The components from the service air system have been incorporated with the instrument air system, and the containment compressed air system was evaluated with the instrument air system components.

The compressed air system consists of two subsystems—the plant compressed air system and the containment compressed air system. Each subsystem employs redundant, oil-free compressors with associated filters, after coolers, moisture separators, air dryers, receivers, and operating controls.

2.3.3.20.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20, UFSAR Section 9.3.1, UFSAR Tables 7.5-1 and 6.2-83, 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 required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.20-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-IA-LR20637 that the applicant depicts 1 in. piping within scope of license renewal for 10 CFR 54.4(a)(3). However, on the continuation LRA drawing PID-1-IA-LR20638, the applicant depicts the 1 in. piping as not being within scope of license renewal. The applicant was asked to justify the exclusion of the 1 in. piping from the scope of license renewal on the LRA drawing PID-1-IA-LR20638.

In its response dated February 3, 2011, the applicant stated that most of the loop B piping is excluded from scope of license renewal due to check valves that prevent backflow into the loop A piping. The applicant referenced that license renewal note 4 on both LRA drawings state "[c]heck valve prevents back flow into other air trains." However, the applicant indicated that there is also a backflow check valve on the 1 in. piping between the air filter and valve V-457, but it was not depicted in LRA drawing PID-1-IA-LR20638 with license renewal note 4. The applicant clarified that the 1 in. piping downstream (and leading into the continuation flag for LRA drawing PID-1-IA-LR20637) from the backflow check valve is within the scope of license renewal under 10 CFR 54.4(a)(3). The applicant also stated that LRA drawing PID-1-IA-LR20638 erroneously depicts this portion of the 1 in. piping as excluded from the scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-01 acceptable because the 1 in. piping was already included within the scope of license renewal under 10 CFR 54.4(a)(3). The staff confirmed that the applicant's description of the scoping boundary of the piping on loop B is consistent with license renewal note 4 on LRA drawing PID-1-IA-LR20638 involving check valves for the instrument air system. Therefore, the staff's concern described in RAI 2.3.3.20-01 is resolved.

In RAI 2.3.3.20-02, dated January 5, 2011, the staff identified the following issues on LRA drawing PID-1-IA-LR20643:

- At locations F-8 and F-9, no continuation piping was identified between the check valve V-531, which is depicted within the scope of license renewal for 10 CFR 54.4(a)(1), and the seismic anchor.
- At locations E-8 and F-8, portions of 2 in. piping near valves (V-533 and V-535) are shown within the scope of license renewal for 10 CFR 54.4 (a)(3). However, the pipe sections upstream of these valves and to the seismic anchors are shown as not within the scope of license renewal.
- At locations E-8 and F-8, the piping associated with the seismic anchors could not be identified on the drawing.
- At location E-8, there is a line whose beginning and end are not identified.

The applicant was asked to do the following:

- provide identification of the continuation piping that is missing between the check valve V-531 and seismic anchor at locations F-8 and F-9
- justify excluding the continuation piping between valves V-533 and V-535 and the seismic anchors from scope of license renewal at locations E-8 and F-8
- identify the missing continuation piping associated with the seismic anchors at locations E-8 and F-8
- identify the line on the drawing at location E-8

In its response dated February 3, 2011, the applicant provided a revised portion to LRA drawing PID-1-IA-LR20643 to include the missing components. The components include piping downstream from check valve V-531, ball valves (V-540, V-532, and V-534), and piping downstream of ball valves V-532 and V-534 up to the seismic supports. The applicant indicated that the above components were included within the scope of license renewal under 10 CFR 54.4(a)(2) and are subject to AMR. The applicant also stated that the tailpipe, which initially appeared in the LRA drawing at location E-8, is attached downstream from the closed ball valve V-540 and is excluded from scope of license renewal since it is not fluid-filled.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-02 acceptable because the applicant clarified the components that are within scope of license renewal. The staff also confirmed that the tailpipe was appropriately excluded from scope of license renewal since it does not serve an intended function beyond closed ball valve V-540. Therefore, the staff's concern described in RAI 2.3.3.20-02 is resolved.

In RAI 2.3.3.20-03, dated January 5, 2011, the staff could not locate seismic anchors on eight nonsafety-related lines connected to safety-related lines in LRA drawing PID-1-IA-LR20647. The applicant was asked to clarify the locations of the seismic anchors.

In its response dated February 3, 2011, the applicant stated both the safety-related and nonsafety-related instrument air piping in the primary auxiliary building are seismically supported by a series of pipe supports. Six of the nonsafety-related lines, which consist of nonsafety-related $^1/_2$ in. tubing, are anchored by the associated instruments, which are rigidly mounted. The applicant also stated that the other two locations of nonsafety-related piping are located near check valves V-8032 and V-8031 and do not contain seismic anchors. The applicant stated that the continued nonsafety-related piping beyond the check valves provides structural support for the safety-related piping to ensure that that the nonsafety-related piping loads are not transferred through the safety and nonsafety interface, as determined by its piping stress analysis.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-03 acceptable because the applicant explained that, based on piping stress analysis, the nonsafety-related piping loads are not transferred through the safety and nonsafety interface. Therefore, seismic anchors are not required, and the staff's concern described in RAI 2.3.3.20-03 is resolved.

2.3.3.20.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the instrument 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 all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.21 Leak Detection System

2.3.3.21.1 Summary of Technical Information in the Application

The leak detection system components monitor indications of leakage inside the containment building by the use of pressure, temperature, and level instruments.

2.3.3.21.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the leak detection system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the leak detection system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.22 Mechanical Seal Supply System

2.3.3.22.1 Summary of Technical Information in the Application

The mechanical seal supply system is designed to supply flushing water to the mechanical seals of the NNS class pumps of the plant. The mechanical seals are provided on these pumps so that no leakage of the process fluid occurs past the shaft into the environment. For their proper functioning, the seal faces have to be kept flushed and under a minimum pressure of 15 psig higher than the process fluid pressure on the suction side of the pump. This ensures the mating of the seal faces without any particulates entrapped between them and does not allow any process fluid to enter the seal cavity (or the stuffing box).

2.3.3.22.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.22 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 required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI, as discussed below.

In RAI 2.3.3.22-01, dated January 5, 2011, the staff noted on drawing PID-1-DM-LR20353, at location H-3, that the applicant refers to license renewal note 1, which indicates that pump SF-P-272 is within the scope of license renewal for 10 CFR 54.4(a)(2). However, on LRA drawing PID-1-SF-LR20484, pump SF-P-272 is not depicted as being within the scope of license renewal. The applicant was asked to clarify the scoping classification for pump SF-P-272.

In its response dated February 3, 2011, the applicant indicated LRA drawing PID-1-DM-LR20353, license renewal note 1, refers to the mechanical seal supply system piping going to the pump SF-P-272. License renewal note 3, on the same drawing, labeled the mechanical seal as a short-lived item, excluding it from the scope of license renewal. The applicant also described the mechanical seal supply piping to the pump mechanical seal as stainless steel material in a treated water internal environment, which is why it was included within scope of license renewal under 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3.3.22-01 acceptable because the applicant clarified that license renewal note 1 in LRA drawing PID-1-DM-LR20353 addressed the mechanical seal piping, which is already included within the scope of license renewal under 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.3.22-01 is resolved.

2.3.3.22.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the mechanical seal 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 all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.23 Miscellaneous Equipment

2.3.3.23.1 Summary of Technical Information in the Application

Miscellaneous equipment contains the hydraulic piping and components that operate the personnel hatch doors for entry into containment. The hydraulic network equalizes air lock pressure, rotates the locking ring to the unlock position, and opens the outer door. On close demand, the network closes the door, closes the equalizing valve, rotates, and locks the locking ring. Similarly, a personnel air lock hydraulic reservoir inside the containment operates with a network of control valves, piping, interlock controls, and actuating pistons. The hydraulic network equalizes air lock pressure, rotates the locking ring to the unlock position, and opens the inner door. On close demand, the network closes the door, closes the equalizing valve, then rotates and locks the locking ring.

2.3.3.23.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the miscellaneous equipment mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the miscellaneous equipment mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.24 Nitrogen Gas System

2.3.3.24.1 Summary of Technical Information in the Application

The function of the nitrogen gas system is to supply nitrogen at controlled pressures to various locations in the unit for the following reasons:

- pressurizing the SI accumulators
- inerting and purging systems
- use as a cover gas
- preventing corrosion during wet and dry lay-up of components

The nitrogen gas system supplies the following major systems and components:

- SI accumulators
- waste processing liquid drains system’s reactor coolant drain tank
- RCS primary relief tank
- waste gas (WG) system
- vent gas (VG) system
- release recovery system tanks
- CS’s volume control tank and letdown degasifier
- resin sluice system tanks
- reactor makeup water tank
- main steam system
- boron recovery system’s primary drain tanks and degasifier
- steam generator blowdown system

2.3.3.24.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the nitrogen gas system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the nitrogen gas system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.25 Oil Collection for Reactor Coolant Pumps System

2.3.3.25.1 Summary of Technical Information in the Application

The seismically-designed lube oil collection system for the four RCPs has been designed with two collection tanks, with two pumps draining to each tank. Each of the two tanks has been sized to contain 125 percent of the oil inventory of one pump. A seismically designed dike has been provided around each tank. Each tank, in combination with its associated dike, has been sized to contain the entire inventory of two pumps. The tanks and the dikes have been located so that the excess oil does not present a fire hazard to any safety-related equipment. Additionally, there is no ignition source near the diked area.

2.3.3.25.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the oil collection for RCPs system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the oil collection for RCPs system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.26 Plant Floor Drain System

2.3.3.26.1 Summary of Technical Information in the Application

The floor drains in this system are located outside any area with a potential for contamination. The plant floor system is located in those areas where automatic sprinkler and spray systems are installed. These drains are sized to pass the expected flows resulting from automatic system actuation, as well as that produced by manual hose application if employed. In areas where hand hose lines are the only water sources used to combat a fire, drains are provided if accumulation of fire-fighting water could result in unacceptable damage to safety-related equipment in the area. In such areas, the operator can use the hose to control the quantity of drain water to avoid unacceptable damage to equipment.

Drainage within the diesel generator building is designed to prevent the spread of fire from one area to another. Other areas with combustible liquids have normally closed shut-off valves in the drain lines or drain directly to the oil and water separation vault.

The electrical tunnels contain no sources of floodwater other than the fire protection system piping. The fire protection system piping consists of zoned preaction dry pipe systems with the zone valves located outside the electrical tunnel areas. The individual fire protection system zones will be actuated by ionization fire detectors. Fire detectors are provided in the areas zoned to provide local indication and an audible and visual alarm in the control room and the guardhouse. Water from the fire protection system will be drained from the tunnel zones to a sump outside the electrical tunnel areas (located in the emergency feedwater pump house). Redundant pumps have been installed in the sump to pump the water collected from the tunnel to the storm drain system (not within the scope of license renewal).

Failure of a circulating water system expansion joint in the turbine building will flood the ground floor pit east of the condensers in the turbine building. Assuming the worst possible failure to be a 2 in. gap all around, the pit would fill up in about 3 minutes, unless prompt action by the operator is taken. There are two level switches (1-DR-LSH-5984 and 5985) in the condenser pit that provide sequential alarms in the control room to warn the operator of the flooded condition. No loss of offsite power is induced by a failure of this equipment provided operator action is taken within 22.2 minutes to mitigate the consequences of the flood.

2.3.3.26.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.26 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 required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI, as discussed below.

In RAI 2.3.3.26-01, dated January 5, 2011, the staff noted LRA Section 2.3.3.26 provides an UFSAR reference of Appendix A, Section F.3, page 41. However, the reference could not be located in the UFSAR that was submitted to the staff with the LRA. The applicant was asked to provide the UFSAR reference for Appendix A, Section F.3, page 41, so that the staff can confirm that the components included in the plant floor drain system have been appropriately identified and included within the scope of license renewal.

In its response dated February 3, 2011, the applicant provided a copy of the UFSAR reference for Appendix A, Section F.3, page 41. UFSAR Section 9.5.1, "Fire Protection System," references the supplemental report, "Evaluation and Comparison to BTP APCSB 9.5-1, Appendix A Report," which describes the floor drain system components used for fire protection.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.26-01 acceptable because the staff reviewed the supplemental report to confirm the plant floor drain system components that are within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.26-01 is resolved.

2.3.3.26.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the plant floor drain system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.27 Potable Water System

2.3.3.27.1 Summary of Technical Information in the Application

Potable water received from the Town of Seabrook water main is metered at the fire pump house and then piped to the fire water storage tanks and the plant distribution system. The fire protection tank fill line is equipped with a backflow preventer. Chlorine injection is provided for control of biological growths in the fire protection tanks and associated piping. The water treatment makeup system uses the undedicated 200,000-gal. capacity of each fire water storage tank as its source of makeup water. The system is not safety-related and is not relied upon to perform a safety-related function.

The distribution system consists of branch mains to the various personnel areas—the service water cooling tower fill, the demineralized water makeup system, and the fire water storage tank fills. Branch headers and branches lead to the various fixtures. Drinking fountains, eye and face wash fountains, lavatories, urinals, water closets, showers, safety showers, water coolers, water heaters, and special fixtures are provided according to occupancy. Connections are provided to kitchen, laboratory, and similar equipment requiring potable water. The branch main to personnel areas is equipped with a backflow preventer and hose bib vacuum breakers to prevent backflow or siphoning.

2.3.3.27.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.27 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 required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3.3.27-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-CBA-LR20303, at locations B-11 and B-12, that the applicant depicts sections of safety-related 12 in. piping directly connected to nonsafety-related 1½ in. piping passing through gate valves V-7 and V-8. The nonsafety-related 1½ in. lines continue through check valve V-3 to the storm sewer. The seismic anchors could not be located for these lines through valves V-7 and V-8 beyond the safety and nonsafety interface. The applicant was asked to provide the seismic anchor locations for the 1½ in. lines.

In its response dated February 3, 2011, the applicant stated that nonsafety-related 1½ in. piping is Seismic Category I and that the Seabrook design review indicated the smaller 1½ in. nominal diameter piping would not impose loads on the larger safety-related piping. The applicant referenced UFSAR 3.7(B).3.3a, in which the branch connections are decoupled from the main runs when the ratio of the branch to run section is equal to or less than 0.05. The applicant indicated that the ratio of the branch (the nonsafety-related 1½ in. piping) to run section (12 in. safety-related piping) moduli is 0.003, which is less than 0.05. Thus, the applicant determined that seismic anchors were not required beyond the safety and nonsafety interface.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.27-01 acceptable because the staff confirmed that the applicant's assessment of the nonsafety-related 1½ in. piping effects onto the safety-related 12 in. piping is consistent with the piping decoupling criteria ,as indicated in the UFSAR, which negated the purpose for establishing seismic anchors on the 1 ½ in. piping. Therefore, the staff's concern described in RAI 2.3.3.27-01 is resolved.

In RAI 2.3.3.27-02, dated January 5, 2011, the staff noted on LRA drawing PID-1-DF-LR20200, at location H-7, that the applicant depicts a section of 4 in. piping within scope of license renewal under 10 CFR 54.4 (a)(2). The 4 in. piping continues to LRA drawing PID-1-SD-LR20402, at location F-7, where it is no longer depicted within scope of license renewal. The applicant was asked to justify the exclusion of the portion of the 4 in. piping from the scope of license renewal on LRA drawing PID-1-SD-LR20402.

In its response dated February 3, 2011, the applicant stated that the 4 in. piping is within scope of license renewal under 10 CFR 54.4 (a)(2) up to the point where it exits the east main steam and feedwater pipe chase. The applicant also stated that LRA drawing PID-1-SD-LR20402 erroneously depicted the 4 in. piping as being excluded from scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.27-02 acceptable because the 4 in. piping on LRA drawing PID-1-SD-LR20402 is within the scope of license renewal and was erroneously depicted as not within scope of license renewal under 10 CFR 54.4 (a)(2). Therefore, the staff's concern described in RAI 2.3.3.27-02 is resolved.

2.3.3.27.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the potable 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 all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.28 Primary Auxiliary Building Air Handling System

2.3.3.28.1 Summary of Technical Information in the Application

The function of the normal heating and ventilating system for the primary auxiliary building is to provide sufficient circulation of filtered outside air for removal of heat generated by lighting and equipment in the summer and to offset building heat losses in the winter, in rooms and areas of the primary auxiliary building. The primary auxiliary building ventilation and heating system (primary auxiliary building air handling) system also supplies conditioned air to the fuel storage building and makeup to the containment enclosure area. Under normal operating conditions, the charging pump rooms are exhausted through this heating and ventilating system.

2.3.3.28.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the primary auxiliary building air handling system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the primary auxiliary building air handling system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.29 Primary Component Cooling Water System

2.3.3.29.1 Summary of Technical Information in the Application

The primary component cooling water system supplies flow to the following safety-related components, which are required for safe shutdown or to ameliorate the consequences of an accident or both:

- containment building spray pumps
- containment building spray heat exchangers
- RHR pumps
- RHR heat exchangers
- SI pumps
- centrifugal charging pumps
- containment enclosure coolers

The system serves as an intermediate fluid barrier between the reactor coolant and service water systems, assuring that leakage of radioactive fluid from the components being cooled is not released to the environment.

The primary component cooling water system consists of loop A and loop B, which are two independent and redundant flow loops, and a RCP thermal barrier loop. Loops A and B each supply component cooling water to one of the redundant components performing engineered safety-related functions to the RCP thermal barrier loop and to other nonsafety-related loads.

A supply and return cross connect and a primary component cooling water head tank outlet line cross connect are included in the system design. Each cross connect consists of two isolation valves. These valves are locked closed when two independent primary component cooling water trains are required to be operable, in accordance with plant technical specifications.

The RCP thermal barrier loop is designed to provide 100 percent of the cooling capacity required to cool the RCP thermal barrier cooling coils under all normal plant operating conditions. The RCP thermal barrier loop has been classified as nonessential, but it incorporates the following special design features to provide a high degree of reliability:

- Primary component cooling water loops A and B each provide cooling to the RCP thermal barrier loop.
- Pipe supports and pressure-retaining system components are designed in accordance with ASME III safety Class 3 and seismic Category I requirements.
- Flow instrumentation trains to the annunciator, pumps, pump drive motors, and associated controls are redundant, are qualified to 1E requirements, and are designed to operate with power from the diesel generators in the event of a loss of offsite power.
- Instrument sensing lines are designed in accordance with the requirements of independent safety analysis (ISA) Standard 67.02-1980.

Those portions of the primary component cooling water system that furnish cooling water to safety-related components are designated safety Class 3, seismic Category I, and are located in seismic Category I structures. The cross connects are designated safety Class 3, seismic Category I and are located in seismic Category I structure.

To provide increased reliability for cooling safety-related components, a cross connect from the fire protection and demineralized water systems to the primary component cooling water system is included in the system design. This cross connect can be used to provide cooling water to the charging pump lube oil coolers or provide emergency makeup water to safety-related portions of the primary component cooling water system. This cross connect is backed up by a seismic Category I service water system and booster pump makeup source.

Those portions of the primary component cooling water system that are non-seismic Category I portions of the system are isolated in the event of a leak. The isolation valves will close on a primary component cooling water head tank low-level alarm. Thus, the system safety function is not compromised in the event of a leak in the nonsafety portion of the system.

2.3.3.29.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.29, UFSAR Section 9.2.2, UFSAR Tables 6.2-83, 7.4-1, and 7.5-1, 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 required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3.3.29-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-CC-LR20205, at locations C-5 and F-7, that the applicant depicts sections of safety-related piping connected to nonsafety-related piping that continue onto LRA drawing PID-1-DM-LR20350. However, the seismic anchors could not be located on the nonsafety-related piping beyond the safety and nonsafety interface on LRA drawing PID-1-DM-LR20350. The applicant was asked to provide the seismic anchor locations on the nonsafety-related piping, as described above, beyond the safety and nonsafety interface.

In its response dated February 3, 2011, the applicant stated that seismic anchors were not depicted on both LRA drawings since all of the demineralized water system piping in the primary auxiliary building was included within the scope of license renewal under 10 CFR 54.4(a)(2) for structural support. The applicant did indicate that a seismic anchor is physically located on piping approximately 6 ft from the safety-related to nonsafety-related interface in one area of LRA drawing PID-1-CC-LR20205. The applicant also stated that the extent of the continued piping and supports ensure that nonsafety-related piping loads are not transferred through the safety and nonsafety interface, as determined by its piping stress analysis.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.29-01 acceptable because all of the nonsafety-related piping in the primary auxiliary building was included within the scope of license renewal under 10 CFR 54.4(a)(2) for structural support. Therefore, the staff's concern described in RAI 2.3.3.29-01 is resolved.

In RAI 2.3.3.29-02, dated January 5, 2011, the staff noted on an LRA drawing that the applicant depicts a section of 1 in. piping within scope of license renewal for 10 CFR 54.4(a)(2). However, the applicant depicts the 1 in. piping as excluded from scope of license renewal in the continuation LRA drawing. The applicant was asked to justify the exclusion of the 1 in. piping from scope of license renewal in LRA drawing PID-1-CS-LR20727.

In its response dated February 3, 2011, the applicant stated that the 1 in. piping shown on the LRA drawing PID-1-CS-LR20727 for the primary auxiliary building is excluded from scope of license renewal due to the chiller surge tank and its associated piping being in the state of dry layup (i.e., not fluid-filled). The applicant also stated that the LRA drawing erroneously depicted the 1 in. piping as being within scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.29-02 acceptable. The staff agrees with the applicant's justification of excluding the above 1 in. piping from scope of license renewal due to its attachment to the chiller surge tank, which is in dry layup and not within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.29-02 is resolved.

In RAI 2.3.3.29-03, dated January 5, 2011, the staff made the following two observations involving the applicant's usage of its methodology described in LRA Section 2.1.2.2.2.

- On LRA drawings PID-1-CC-LR20205 (loop A) and PID-1-CC-LR20211 (loop B), respectively, the applicant depicts sections of safety-related piping connected to nonsafety-related piping that are within the scope of license renewal for 10 CFR 54.4(a)(2). No seismic anchors are indicated on these LRA drawings. These lines continue on LRA drawing PID-1-FP-LR20268, at location B-9, where seismic anchors could not be located on the nonsafety-related piping beyond the safety and nonsafety interface.

- On LRA drawing PI D-1-CC-LR20211, the applicant depicts a section of safety-related piping connected to nonsafety-related piping as being within the scope of license renewal. The piping continues onto LRA drawing PID-1-DM-LR20350, where a seismic anchor could not be located on the nonsafety-related piping beyond the safety and nonsafety interface.

The applicant was asked to provide the seismic anchor locations on the nonsafety-related piping beyond the safety and nonsafety interface as described in both of the above issues.

In its response dated February 3, 2011, the applicant addressed the first issue by stating that for LRA drawings PID-1-CC-LR20205 (loop A) and PID-1-CC-LR20211 (loop B), seismic anchors are excluded on the nonsafety-related piping beyond the safety and nonsafety interface because the nonsafety-related piping, which continues onto LRA drawing PID-1-CC-LR20205 does the following:

- provides structural support for the piping beyond the safety and nonsafety interface
- ensures that nonsafety-related piping loads are not transferred through the interface as determined by its piping stress analysis

For the second issue, the applicant stated that for LRA drawing PID-1-CC-LR20211, seismic anchors are excluded on the nonsafety-related piping beyond the safety and nonsafety interface because the piping, which continues onto LRA drawing PID-1-DM-LR20350, does the following:

- provides structural support for the piping beyond the safety and nonsafety interface
- ensures that nonsafety-related piping loads are not transferred through the interface as determined by its piping stress analysis

Based on its review, the staff finds the applicant's response to RAI 2.3.3.29-03 acceptable because the applicant explained that no seismic anchors are required because the piping stress analyses determined that nonsafety-related piping loads are not transferred through the interface. Therefore, the staff's concern described in RAI 2.3.3.29-03 is resolved.

2.3.3.29.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the primary component 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 all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.30 Radiation Monitoring System

2.3.3.30.1 Summary of Technical Information in the Application

The radiation data management system (radiation monitoring (RM) system) consists of three subsystems:the process and effluent RM system, the area RM system, and the airborne and particulate radioactivity monitoring system. The functional performance requirements for the RM system include the following:

- warn of leakage from process systems containing radioactivity
- monitor the amount of radioactivity released in effluents
- isolate lines containing liquid and gaseous activity when activity levels reach a preset limit
- record the radioactivity present in various station systems and effluent streams
- provide a means for leakage detection
- provide information on failed fuel
- monitor plant areas within the radiologically controlled area for radiation

2.3.3.30.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the RM system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the RM system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.31 Reactor Makeup Water System

2.3.3.31.1 Summary of Technical Information in the Application

The reactor makeup water system provides the storage and distribution of reactor grade water. It also provides storage capacity for water recycled by the boron recovery system.

The reactor makeup water system consists of one reactor water storage tank, two redundant, full capacity reactor makeup water pumps, and associated piping, valves, instrumentation, and controls.

The intended functions of the reactor makeup water system component types within the scope of license renewal include the following:

- maintain system interface with the CS and the containment building spray system
- provide post-accident monitoring
- provide containment isolation function

LRA Table 2.3.3-31 lists the reactor makeup water system components types that require AMR.

2.3.3.31.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the reactor makeup water system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the reactor makeup water system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.32 Release Recovery System

2.3.3.32.1 Summary of Technical Information in the Application

The release recovery system contains and quenches relief valve discharge from the CS and boron recovery system degasifiers as well as the boron recovery system, steam generator blowdown system, and waste processing liquid system evaporators.

Release recovery tank, 1-RR-TK-258, is in-scope for license renewal from a spatial consideration due to its location in the primary auxiliary building. The relief valve in the degasifier system opens at 60 psig to direct flow to the release recovery tank, 1-RR-TK-258, located in the primary auxiliary building hallway, outside the degasifier cubicle. Quench tank, 1-RR-TK-258, and the release recovery system piping will normally be under a nitrogen blanket to eliminate the potential for explosive gas mixtures if H_2 is present in the relieving fluid. Under normal conditions, 1-RR-TK-258 will be half filled with demineralized water to ensure that quenching of a design base release can be accomplished. The tank is designed for an 8 second release from full open 1-RR-V-655.

2.3.3.32.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the release recovery system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the release recovery system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.33 Resin Sluicing System

2.3.3.33.1 Summary of Technical Information in the Application

The spent resin sluicing (RS) system collects the spent resin from all the demineralizers and ion exchangers of the nuclear plant.

2.3.3.33.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the RS system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the RS system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.34 Roof Drains System

2.3.3.34.1 Summary of Technical Information in the Application

The roof drains system is nonsafety-related. It is installed on major buildings that have relatively flat roofs. The system removes rainwater and water from melting snow from the roof. It consists of roof-mounted strainers that collect the water and transport it through connected ceiling mounted pipes to the storm drain system (not within the scope of license renewal). The plant's dewatering system discharges water to the roof drains system, which then flows to the storm drain system and out to the circulating water system for discharge.

2.3.3.34.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.34 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 required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI, as discussed below.

In RAI 2.3.3.34-01, dated January 5, 2011, the staff noted on LRA drawing, PID-1-DR-LR20633, that the applicant depicts 6 in. lines that continue onto LRA drawing PID-1-SD-20402. On LRA drawing PID-1-DR-LR20633, the applicant depicts 6 in. piping that enters the continuation flag marked "B" as being included within scope of license renewal under 10 CFR 54.4(a)(2). The applicant depicts the other 6 in. piping that enters the continuation flag, marked "C," as being excluded from scope of license renewal. However, the applicant depicts on the continuation LRA drawing, PID-1-SD-20402, the 6 in. piping for "B" as being excluded from scope of license renewal, while the other 6 in. piping for "C" is shown as being included within scope of license renewal. The applicant was asked to clarify the scoping classifications of both 6 in. piping sections on both LRA drawings.

In its response dated February 3, 2011, the applicant stated that the 6 in. piping in LRA drawing PID-1-SD-LR20402, which is marked with the "B" continuation flag, is within scope of license renewal for 10 CFR 54.4 (a)(2) up to the area where it exits the emergency feedwater pumphouse (EFPH). The applicant also stated that the 6 in. piping in LRA drawing PID-1-DR-LR20633, which is marked with the "B" continuation flag, was excluded from scope of license renewal from where it exits the EFPH. Lastly, the applicant stated that the 6 in. piping in LRA drawing PID-1-SD-LR20402, which is marked with the "C" continuation flag, was excluded from scope of license renewal from where it exits the EFPH. The applicant indicated that both 6 in. roof drain lines in the EFPH are within the scope of license renewal up to the point where they exit the EFPH.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.34-01 acceptable because the applicant explained that the piping in the EFPH is within the scope of license renewal. The piping is not within the scope of license renewal after it leaves the EFPH. Therefore, the staff's concern described in RAI 2.3.3.34-01 is resolved.

2.3.3.34.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the roof drains system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.35 Sample System

2.3.3.35.1 Summary of Technical Information in the Application

The sample subsystems from the reactor coolant, steam generators, and other auxiliary systems provide representative gas and liquid samples for laboratory analysis, in accordance with RG 1.21, Positions C.6 and C.7. Typical information obtained includes reactor coolant boron, sodium ion and halogen concentrations, fission product radioactivity level, H_2, oxygen, and fission gas content, corrosion product concentration, and chemical additive concentration. The sample subsystem for secondary steam and water systems provides representative samples for measuring specific and cation conductivity, concentrations of sodium ion, dissolved oxygen, and hydrazine.

The system is divided into five subsystems—reactor coolant sampling, steam generator blowdown sampling, auxiliary system sampling, secondary steam and water sampling, and post-accident sampling.

2.3.3.35.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.35, UFSAR Sections 9.2.3.1 and 9.3.2.2, UFSAR Tables 6.2-83 and 7.5-1, 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 required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI, as discussed below.

In RAI 2.3.3.35-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-SB-LR20626, at location B-12, that the applicant depicts a section of 3 in. piping within scope of license renewal under 10 CFR 54.4(a)(3). The 3 in. piping continues onto LRA drawing PID-1-SB-LR20629, in which the 3 in. piping is excluded from scope of license renewal. The applicant was asked to justify the exclusion of this portion of 3 in. piping from scope of license renewal on LRA drawing PID-1-SB-LR20629.

In its response dated February 3, 2011, the applicant stated that the in-scope portion of the 3 in. piping on LRA drawing PID-1-SB-LR20626 should have ended before continuing onto LRA drawing PID-1-SB-LR20629. The applicant stated that license renewal note 3 in LRA drawing PID-1-SB-LR20626, which indicates that "[p]ipe exits Waste Process Building Tank Farm area and is not subject to aging management review," should have been labeled near the 3 in. piping where it exits the tank farm on the LRA drawing.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.35-01 acceptable because the staff confirmed that the scoping boundary of the 3 in. piping is consistent with license renewal note 3 in LRA drawing PID-1-SB-LR20626 regarding piping that exits the waste process building tank farm area. Therefore, the staff's concern described in RAI 2.3.3.35-01 is resolved.

2.3.3.35.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the sample system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.36 Screen Wash System

2.3.3.36.1 Summary of Technical Information in the Application

The service water traveling screens form a full-channel mesh strainer that removes debris from the water flowing into each service water pump bay. The debris collected on the screen is removed by a high-pressure water spray supplied by the service water screen wash pump.

The circulating water traveling screens prevent fish and debris from entering the circulating water system. One traveling screen is provided for each circulating water pump bay. Debris is collected on the upstream side of the traveling screen and is carried upward as the screen rotates. As the debris nears the top of screen travel, high velocity jets of water from the screen wash nozzles flush it out.

The circulating water screen wash pumps are one means to supply the chlorination system with salt water. Flow to the chlorination system from the screen wash system pumps goes through a common header. The sodium hypochlorite metering pumps discharge into this common header.

During initial startup or total circulating water system shutdown, water is supplied to one of two circulating water lube water pumps from the service water screen wash pump.

2.3.3.36.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the screen wash system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the screen wash system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.37 Service Water System

2.3.3.37.1 Summary of Technical Information in the Application

The service water system was originally designed for two units. The service water pump house has a pump bay for each unit. Each pump bay has two supplies one from the intake discharge transition structure and one from the discharge transition structure. The Unit 2 supply valves are locked, closed, and de-energized. Unit 2 was not completed and is non-operational. The Unit 2 service water return is blanked off and is not used.

The Unit 1 service water system consists of two independent and redundant flow trains. Each of these supplies cooling water to a primary component cooling water heat exchanger, a diesel generator jacket water cooler, the secondary component cooling water heat exchangers, the auxiliary secondary component cooling water heat exchangers, the condenser water box priming pump seal water heat exchangers, and—except during a LOCA—the fire protection system during a fire.

Flow in each redundant train is supplied by two redundant service water pumps. Each service water pump is capable of supplying 100 percent of the flow required by each flow train to dissipate plant heat loads during normal full power operation. Thus, for full power operation, two pumps (one pump per flow train) are required.

The four service water pumps take suction from a common bay in the service water pumphouse. Seawater flow is supplied to the service water pumphouse from the Atlantic Ocean due to the static head of the ocean above the elevation of the service water pumps.

The Atlantic Ocean serves as the normal ultimate heat sink for Seabrook. In the unlikely event that seawater flow to the service water pumphouse is restricted (greater than 95 percent blockage) due to seismically induced damage to the circulating water (seawater) intake and discharge tunnels, a mechanical draft evaporative cooling tower is provided to dissipate shutdown and accident heat loads. The mechanical draft cooling tower is completely independent of the circulating water tunnels and the Atlantic Ocean.

The cooling tower consists of one independent cell with one fan and a center cell with two fans. A third cell was included for anticipated Unit 2 operation but remains nonfunctional. The cooling tower basin consists of a pump well and one catch basin for each of the two tower spray cells. The unit has an “A” and a “B” cooling tower complex flow train. The cooling tower pumps—with associated valves, piping, and equipment in the trains—circulate cooling water from the pump well basin through the primary component cooling heat exchangers, the secondary component cooling water heat exchangers during normal operations, the diesel generator heat exchangers during loss of offsite power conditions, or both during testing.

Makeup to the cooling tower can be provided by a portable tower makeup pump (in the event that normal makeup source is unavailable and the service water pumps are unavailable). RG 1.27 requires a heat sink capable of providing cooling for 30 days; the cooling tower has a 7-day supply. The cooling tower makeup pump is tested every 18 months per technical specifications. After the pump is tested, it is flushed with potable water. It is capable of providing makeup water to the tower basin from the nearby Browns River or Hampton Harbor, with several locations accessible by road. It consists of 3,000 ft of 5-in. rubber-lined polyester flexible hose and associated hose couplings and a portable diesel-driven pump that is self-priming within 15 ft of water level, and it is designed to deliver a minimum of 200 gallons per minute (gpm) from the water source to the tower basin. The 7-day period that the tower can operate without makeup water provides sufficient time to move the pump into position, lay the hose, and make the system ready for operation.

2.3.3.37.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.37, UFSAR Sections 9.2.1 and 9.2.5, UFSAR Tables 7.4-1 and 7.5-1, 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 required to complete the review of the applicant’s scoping and screening results. The applicant responded to the staff’s RAI, as discussed below.

In RAI 2.3.3.37-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-SW-LR20795, at locations B-11 and C-12, that the applicant depicts strainers within scope of license renewal under 10 CFR 54.4(a)(1). However, the component type “strainer” and its component intended function(s) are not included in LRA Table 2.3.3-37. The applicant was asked to justify the exclusion of the strainer and its component intended function(s) from LRA Table 2.3.3-37.

In its response dated February 3, 2011, the applicant stated that the strainers are evaluated as component type “filter housing” with an intended function of “pressure boundary” in LRA Table 2.3.3-37. The applicant also stated that the screen portion of the strainer was evaluated as component type “filter element” with an intended function of “filter” in LRA Table 2.3.3-37.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.37-01 acceptable because the staff confirmed that both the component types, “filter housing” and “filter,” are included in LRA Table 2.3.3-37. Therefore, the staff’s concern described in RAI 2.3.3.37-01 is resolved.

2.3.3.37.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff’s review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant 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 all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.38 Service Water Pump House Air Handling System

2.3.3.38.1 Summary of Technical Information in the Application

The service water pump house heating and ventilation systems are comprised of the heating and ventilation systems for the pump room area of the service water pump house.

The ventilation function is provided by the service water pump house air handling system. The heating function is provided by the HW system and is evaluated separately.

The pump room area is ventilated and cooled with outside air supplied through pneumatically-operated dampers, and it is exhausted through exhaust fans and backdraft dampers. Each exhaust fan, and its associated supply air damper, is controlled by a separate thermostat located in the pump room area. The thermostat settings are staggered such that the fans will start in sequence. Each fan is powered by a separate and independent engineered safety features electrical train. Each supply air damper is designed to fail open on loss of air or electric power to its solenoid valve.

The switchgear areas of the service water pump house, one for electrical train A equipment and the other for electrical train B equipment, are ventilated with filtered outside air supplied by one of two full-sized supply fans through a seismically supported duct system. Each fan is powered by a separate and independent engineered safety features electrical train. Air is drawn from the outside through a roll-type filter, a fan, or a backdraft damper and is then distributed through ductwork into the two switchgear areas. Air is exhausted from each switchgear area through its respective relief damper. There are two thermostats per fan to control its operation, one in train A switchgear room and the other in train B switchgear room. Both the thermostats on the lead fan have identical set points.

The service water cooling tower heating and ventilation systems are comprised of a heating system and a ventilation system for each redundant switchgear room and a ventilation system for the pump room. Each switchgear room and the pump room are ventilated by drawing air from, and exhausting to, the outside.

Ventilation and cooling air is drawn into the ventilation and mechanical equipment area of the pump room from the outside through fixed louvers and a roughing filter.

Cooling of the pump room area, when required, is accomplished by redundant exhaust fans. Each fan is controlled by its individual thermostat. Thermostats are set so if one thermostat, fan, or its power supply fails, the redundant fan, served by a separate Class 1E power supply, will start before overheating occurs.

Each of the two cooling tower switchgear rooms is supplied with ventilating and cooling air, when required, from its own independent supply fan located in the mechanical equipment area. The supply air fan for each switchgear room is provided electrical power for a Class 1E power source, which is independent of the other three. Each supply fan is cycled by a thermostat located in its respective switchgear room. Supply air is directed to the switchgear room via sheet metal ductwork. Heat-laden air from the switchgear rooms is exhausted through a relief damper to the outside.

2.3.3.38.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the service water pump house air handling system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the service water pump house air handling system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.39 Spent Fuel Pool Cooling System

2.3.3.39.1 Summary of Technical Information in the Application

The functions of the spent fuel pool cooling and cleanup system include the following:

- continuously remove decay heat generated by fuel elements stored in the pool
- continuously maintain a minimum of 13 ft of water over the spent fuel elements to shield personnel
- maintain the chemical parameters and optical clarity of the spent fuel pool water and the water in the reactor cavity and refueling canal during refueling operations

All portions of the spent fuel pool cooling loop are designated safety Class 3 and are designed and constructed to meet seismic Category I requirements. Those portions of the cleanup system not designed to these requirements are normally isolated from the cooling loop.

The spent fuel pool cooling and cleanup system is comprised of three subsystems:the spent fuel pool cooling subsystem, the spent fuel pool cleanup subsystem, and the reactor cavity and canal cleanup subsystem.

Spent Fuel Pool Cooling Subsystem. The spent fuel cooling pumps take suction from the pool and circulate water through the heat exchangers, which are cooled by the primary component cooling water system. Pool water enters the suction line through a strainer near one wall of the pool at a point 13 ft higher than the return line terminations. The return lines are located at a sufficient distance from the suction line to assure adequate circulation and uniform pool water temperatures. All system connections to the fuel pool penetrate at elevations sufficiently above the top of the fuel to maintain adequate shielding in the event the water level drains to the penetration level. Piping arrangement precludes siphoning below this level. All components in contact with the spent fuel cooling water are stainless steel. The spent fuel pool pump motors are Class 1E motors. Pumps 1-SF-P-10A and 1-SF-P-10B are powered from separate emergency busses. Pump 1-SF-P10C can be aligned to be powered from either emergency bus.

Spent Fuel Pool Cleanup Subsystem. Spent fuel pool water quality is maintained by a pool skimmer loop, which filters and demineralizes the circulated water. The pool skimmer loop consists of five pool surface skimmers, a skimmer pump, two filters, and a demineralizer. This system is used to maintain the pool surface free from floating particles and other materials and to remove radioactive materials in the water. The system is sized to process approximately 120 gpm, which means that one-half of the pool volume is processed in a day. All spent fuel pool cooling and cleanup system equipment is located in the fuel storage building, except the filters and demineralizer, which are located in the demineralizer area of the primary auxiliary building. The skimmer pump motor is not Class 1E and is supplied from a local control center. The spent fuel pool cleanup subsystem can also be used to purify the RWST water, drain the water in the cask loading and fuel transfer canal areas (using a submersible pump), and purify the refueling cavity water during refueling operations. A cleanup system (1-CBS-SKD-161) is also used for RWST or spent fuel pool processing.

Reactor Cavity and Canal Cleanup Subsystem. The reactor cavity cleanup portion of the system is designed to purify the reactor cavity during refueling operations to improve the optical clarity of the water. The system consists of five surface skimmers at the water surface of the refueling cavity and canal and three drains, all piped to the suction of the reactor cavity cleanup skimmer pump via a lead-shielded disposable cartridge type filter unit. The lead-shielded filter removes radioactive particulate in the refueling water in order to prevent crud buildup in socket-welded piping downstream of the skimmer pump. This filter also minimizes crud buildup in the CS and spent fuel pool cleanup system filters and demineralizers depending on the particular lineup. The cavity water is pumped through the CS mixed bed demineralizer and filters to the suction of the RHR pumps where it is returned to a cold leg through an RHR heat exchanger. During cavity drain down upon completion of refueling, refueling water can be routed via the reactor cavity cleanup system to the RWST via the spent fuel pool cleanup system. Also, the reactor cavity cleanup system may be used to send refueling water to the liquid waste system floor drain tanks. This lineup would be primarily used at the conclusion of drain down when the residual refueling water may not be suitable for return to the RWST. As an alternative to using the installed cavity cleanup pump and shielded filter, a provision exists to install temporary equipment between isolation valves 1-SF-V-81 and 85. The reactor cavity cleanup pump motor is not Class 1E, and it is supplied from a motor control center in the control building.

2.3.3.39.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.39, UFSAR Sections 9.1.2 and 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 required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.39-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-SF-LR20484 that the applicant refers to license renewal note 1, which states "[t]hese components are drained during operation so therefore they have an internal environment of air/gas so they have no license renewal (LR) intended function and not in scope." However, on LRA drawing PID-1-DM-LR20353, license renewal note 1 indicates refueling canal skimmer pump SF-P-272 is a component that is in-scope for license renewal, which contradicts license renewal note 1 on LRA drawing PID-1-SF-LR20484. Additionally, the portion of the line excluded from scope of license renewal is directly connected to the pump P-272 and continues onto the refueling pool and canal skimmers. LRA Table 3.3.2-39 does not provide an internal environment of air or gas for pump casing. The applicant was asked to clarify the scoping designation of the piping directly connected to the refueling canal skimmer pump.

In its response dated February 3, 2011, the applicant stated the pump SF-P-272 is a nonsafety-related pump and is in operation only during refueling outages when the refueling pool and canal are flooded. The applicant also stated that the pump and associated piping are drained during normal power operation and are excluded from scope of license renewal. The applicant described that license renewal note 1, found in LRA drawing PID-1-DM-LR20353, refers to only the mechanical seal supply system piping attached to the pump mechanical seal in containment as being included within scope of license renewal under 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3.3.39-01 acceptable because the SF-P-272 pump and its piping do not have any license renewal-intended functions and are drained during normal power operation. Therefore, the staff's concern described in RAI 2.3.3.39-01 is resolved.

In RAI 2.3.3.39-02, dated January 5, 2011, the staff identified a discrepancy between the CLB and LRA descriptions of the alternate spent fuel pool cooling (ASFPC) heat exchanger. The applicant states in the UFSAR that the ASFPC heat exchanger is available and can be placed in service as needed. However, the applicant also describes in the LRA that the ASFPC heat exchanger is blank-flanged and is in abandoned status. The applicant was asked to clarify if the ASFPC heat exchanger is available as part of the spent fuel pool cooling system and if the component is in-scope for license renewal.

In its response dated February 3, 2011, the applicant stated that an UFSAR change request has been issued to remove the discussion of the ASFPC from the UFSAR, excluding it from scope of license renewal. The applicant indicated that UFSAR Section 9.1.3.1 has been revised to indicate the ASFPC system is no longer required and is isolated from the service water and spent fuel pool cooling systems. The applicant stated that other sections in the UFSAR that reference the ASFPC were also deleted.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.39-02 acceptable because the ASFPC is isolated from the service water and spent fuel pool cooling systems; thereby excluding it from scope of license renewal. The applicant stated that an UFSAR change request has been issued to remove all references to the ASFPC heat exchanger. Therefore, the staff's concern described in RAI 2.3.3.39-02 is resolved.

2.3.3.39.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the spent fuel pool cooling system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.40 Switchyard

2.3.3.40.1 Summary of Technical Information in the Application

The 345-kV switching station consists of metal-enclosed, gas-insulated components (circuit breakers, disconnect switches, buses, surge arresters, potential devices, etc.) connected by an integral bus system. Pressurized sulphur hexafluoride (SF_6), a nonflammable, nontoxic gas, is used as the insulating and arc-quenching medium. Each circuit breaker and each bus section of the 345-kV switching station forms a separate gas-insulated system that is individually monitored as a three-phase system. Each three-phase circuit breaker is supplied with its own self-contained SF_6 gas system. There is no interconnection between the circuit breaker SF_6 gas systems and the switching station gas systems.

The bus section gas systems include the three-phase bus connections between two circuit breakers, extending to the point of connection to a transformer or to an overhead line. Metal-enclosed, SF_6-insulated buses connect the 345-kV switching station directly to the high-voltage bushings of the generator step-up (GSU) transformers and the reserve auxiliary transformers (RATs). The electrical configuration of the 345-kV switching station is a breaker-and-half arrangement.

2.3.3.40.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the switchyard mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the switchyard mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.41 Valve Stem Leak-off System

2.3.3.41.1 Summary of Technical Information in the Application

The valve stem leak-off system collects any stem leakage and directs it to a low point drain. This helps reduce the spread of contamination and keeps the water off the floor.

Initially, all manually and motor-operated valves of the RCS, which are 3 in. and larger were provided with double-packed stuffing boxes and intermediate lantern ring leakoff connections. Exceptions to this criterion are gate valves that have been determined to be susceptible to pressure locking, which have been modified to use the valve stem leakoff connection as a vent path for the bonnet cavity. Packing configurations have evolved so that the preferred packing configuration is a single packing set. The industry has moved away from double packed stuffing boxes. These changes in packing configuration have been approved for use at Seabrook. Accordingly, either packing design configuration is acceptable for use at Seabrook. These valves use only a single packing set. Leakage to the atmosphere is essentially zero for these valves.

2.3.3.41.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.41, UFSAR Sections 9.2.3.1 and 9.3.2.2, UFSAR Tables 6.2-83 and 7.5-1, 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. In addition to the continuation issue identified in RAI 2.3-01 described in Section 2.3.3, the staff's review identified areas in which additional information was required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.41-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-VSL-LR20776, at locations F-4 and F-11, that the applicant depicts four vent pipelines within scope for license renewal for 10 CFR 54.4 (a)(2). However, the valves associated with these vent lines are not listed on LRA Table 2.3.3-41 as a valve component type with intended function(s). The applicant was asked to justify the exclusion of the valves from LRA Table 2.3.3-41.

In its response dated February 3, 2011, the applicant stated the valves are the instrument vent valves for the primary component cooling water system flow indicating switches. The applicant indicated that the instrument valves are within scope of license renewal under the primary component cooling water system as a commodity. The applicant also indicated that a system flag designator should have been included on LRA drawing PID-1-VSL-LR20776 to denote that the vent valves were part of the primary component cooling water system.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.41-01 acceptable because the staff confirmed that the instrument vent valves were already included within scope of license renewal as instrument commodities for the primary component cooling water system. Therefore, the staff's concern described in RAI 2.3.3.41-01 is resolved.

In RAI 2.3.3.41-02, dated January 5, 2011, the staff noted on LRA drawing PID-1-VSL-LR20776, at locations F-4 and F-11, that the applicant depicts four vent pipelines within scope of license renewal under 10 CFR 54.4 (a)(2). However, the seismic anchors could not be located on the nonsafety-related piping beyond the safety and nonsafety interface. The applicant was asked to provide the seismic anchor locations on the nonsafety-related piping beyond the safety and nonsafety interface.

In its response dated February 3, 2011, the applicant stated that the safety-related piping to nonsafety-related piping (or tubing) transition is through a flexible connector. The applicant explained that seismic anchors are not required since the flexible connectors decouple the piping system and negate a transfer of loads. However, the applicant indicated that the entire nonsafety-related piping (or tubing) was included within scope of license renewal and subject to AMR to ensure adequate protection of the safety-related piping. The applicant also indicated that the instrument racks, which contain the instruments that connect to the tubing, serve as the seismic anchors for the valves, tubing, and instruments and are also included within scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.41-02 acceptable because the nonsafety-related piping beyond the safety and nonsafety interface and connected to the instrument racks was already included within the scope of license renewal and subject to AMR. Therefore, the staff's concern described in RAI 2.3.3.41-02 is resolved.

2.3.3.41.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the valve stem leak-off system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.42 Vent Gas System

2.3.3.42.1 Summary of Technical Information in the Application

The equipment vent gas (VG) system consists of three separate and distinct headers:an aerated vent header, a hydrogenated vent header, and a reactor coolant vent header. Local vents are not considered a part of this system but are vented to nearby ventilation system ducts.

<u>Aerated Vent Header</u>. The aerated vent header receives vent gas that is predominantly air plus radioactive contaminants from various components in the boron recovery system, liquid waste system (waste processing liquid system), waste solidification system, steam generator blowdown system, equipment and floor drainage system (waste processing liquid drains system), and the letdown degasifier during an oxygenated letdown sequence. The gas is then filtered and discharged to the atmosphere via the primary auxiliary building normal ventilation cleanup exhaust unit.

<u>Hydrogenated Vent Header</u>: The hydrogenated vent header collects radioactive contaminated H_2 gas from the reactor coolant drain tank, chemical volume control tank, pressurizer relief tank sample vessel, chemical volume control tank sample vessel, primary drain tank, primary drain tank degasifier, and the letdown degasifier. Additionally, dependent on gaseous activity, the pressurizer may be purged to the hydrogenated vent header in preparation for outages. The collected gas is then processed through the radioactive gaseous waste system (WG system). The safety valve surge tank provides additional header capacity and reduces the magnitude of pressure fluctuations within the header. A pressure-regulating valve maintains a constant pressure of 2 psig in the influent line of the radioactive gaseous waste system that serves to isolate the radioactive gaseous waste system influent line from hydrogenated vent header pressure surges.

<u>Reactor Coolant Vent Header</u>. The reactor coolant vent header provides for the evacuation of the RCS during filling operations. Additionally, dependent on gaseous activity, the pressurizer may be purged to the hydrogenated vent header via the reactor coolant vent header in preparation for outages. During normal plant operations, the reactor coolant vent header is isolated from the hydrogenated vent header by a locked closed valve. Prior to the RCS filling

operation, the hydrogenated vent header is isolated from the reactor coolant vent header, except for a path to the primary auxiliary building exhaust unit, and the line is purged with nitrogen. The reactor coolant vent header is then connected to the components and piping of the RCS by the insertion of a spool piece between the vent line. A separator and silencer separates any entrained liquid, which is then drained to containment sump “A.” Prior to entering an outage and the opening of the RCS, the pressurizer gas space may be purged to the primary auxiliary building exhaust unit or the hydrogenated vent header dependent on gaseous activity. When routed to the hydrogenated vent header, the reactor coolant vent header is aligned to the pressurizer via the vent spool and purged with nitrogen. Following completion of the pressurizer purge, the reactor coolant vent header is isolated from the hydrogenated vent header. An evacuation pump is used during filling operations to direct the air from the reactor coolant vent header to the hydrogenated vent header, where it is filtered and discharged to the atmosphere.

2.3.3.42.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the VG system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the VG system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.43 Waste Gas System

2.3.3.43.1 Summary of Technical Information in the Application

Hydrogenated fission product gases—from the reactor coolant letdown stream and from the liquids collected in the primary drain tank and the reactor coolant drain tank—are processed in the radioactive gaseous waste (WG) system. An iodine guard bed and a molecular sieve dryer reduce the contamination level of the gases before further processing by the carbon delay beds. The carbon delay beds provide a minimum of 60 days xenon delay and 85 hours krypton delay. Low activity aerated gas streams from the reactor plant aerated vent header and condenser vacuum pump units are filtered, monitored, and discharged to the plant unit vent.

The WG system is designed to provide sufficient processing so that gaseous effluents are discharged to the environment at concentrations below the regulatory limits of 10 CFR 20 and within the “as low as is reasonably achievable” guidelines set forth in 10 CFR Part 50, Appendix I. The WG system also provides sufficient holdup and control of gaseous releases, as specified in 10 CFR Part 50, Appendix A, GDC 60. The WG system can process a maximum surge flow of 1.2 standard cubic feet per minute (SCFM) from the degasifiers, which is based on the maximum letdown flow of 120 gpm from the RCS to the CS. This represents the most limiting plant operating condition for the WG system.

The portion of the waste processing building that houses the WG system is seismic Category I.

The WG system is designated NNS-related. H_2 concentration is monitored in cubicles containing WG system components to detect a leak in the system. Monitoring of H_2 concentration is not required while the WG system is inerted with nitrogen. Dual oxygen monitors are provided to sample the process stream to monitor formation of explosive mixtures. An alarm is initiated at a predetermined setpoint prior to reaching a potentially explosive mixture. The WG system is designed to withstand an H_2 explosion.

The WG stream undergoes one of the following options:

- It is returned directly to the RCS via the volume control tank or the H_2 injector.
- It is stored in the H_2 surge tank.
- It is released to the environment via the equipment vent system.
- It is recycled to the hydrogenated vent header as makeup gas.

2.3.3.43.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the WG system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the WG system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.44 Waste Processing Liquid System

2.3.3.44.1 Summary of Technical Information in the Application

The liquid waste system (waste processing liquid system) is nonnuclear safety class (NNS) and non-seismic Category I, in accordance with RG 1.26 and RG 1.29. The liquid waste system is designed to meet applicable requirements specified in 10 CFR, Part 20 and 10 CFR Part 50, as follows:

- provide a central collection point for radioactive liquid waste (This includes approximately 1,200 gal. per week of reactor grade and nonreactor grade leakage from various systems and approximately 400 gal. per week of floor drainage from area wash down.)
- provide preliminary processing through the use of a strainer and filters
- concentrate nonvolatile and, to some extent, volatile radioactive liquid contaminants, through evaporation, with a minimum decontamination factor (D.F. = Ratio of specific activity in the bottoms and distillate) of 104, at a bottoms concentration of 12 percent by weight
- concentrate the residual contaminants (bottoms) up to 12 percent total dissolved solids for transfer to the waste solidification system
- produce up to 25 gpm of distillate from the evaporator and condenser (The distillate is demineralized (if necessary) and tested in the waste processing liquid waste test tank before disposal offsite.)
- maintain, during normal operation, the radioactivity content of liquid effluents from the Seabrook site within the concentration limits expressed in 10 CFR Part 20, Appendix B, Table II, Column 2, on an instantaneous release basis and on an annual average release basis to maintain the radioactive liquid effluents so that the dose guidelines expressed in the Appendix I to 10 CFR Part 50 are not exceeded

- provide processing equipment and capacity sufficient to maintain radioactivity in liquid effluents within the applicable flexibility provisions of Appendix I to 10 CFR Part 50 during anticipated operational occurrences

2.3.3.44.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the waste processing liquid system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the waste processing liquid system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.45 Waste Processing Liquid Drains System

2.3.3.45.1 Summary of Technical Information in the Application

This system includes tanks, sumps, pumps, piping and instrumentation, as required, to collect, segregate and control liquid leakage within the radioactively contaminated portions of the plant.

The equipment and floor drainage system (waste processing liquid drains system) is operable during all normal modes of operation. The entire system is classified as NNS, non-seismic Category I, non-Class 1E, with the exception of piping runs through the containment walls and the isolation valves for these penetrations.

The system is designed to handle all anticipated normal leakage volumes from component and liquid drain sources within the area covered by the equipment and floor drainage system.

The system is also designed to handle all anticipated abnormal leakage from sources such as malfunctioning pump seals, leaky flange gaskets, and blown valve stem packing. The maximum expected flow rate into any one sump from all expected abnormal sources is less than the 50 gpm capacity of the sumps in areas containing safety class equipment. Abnormal flows from pipe breaks are not included in the system design.

2.3.3.45.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.45, UFSAR Sections 9.3.3 and 9.3.2.2, UFSAR Tables 6.2-83 and 7.5-1, 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 required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.45-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-WLD-LR20218, at location G-6, that the applicant labels license renewal note 2, which states "[c]omponents have an internal environment of air/gas so they have no license renewal-intended function and are not in scope." The portion of the 2 in. piping excluded from scope of license renewal is directly connected to the in-scope reactor coolant drain tank and continues up to the relief valve V-83. LRA Table 3.3.2-45 does not list an internal environment of air or gas for tanks. The staff is concerned with conditions where the relief valves actuate and the piping is fluid-filled during a DBE. The applicant was asked to do one of the following:

- include the piping attached to the reactor coolant drain tank within the scope of license renewal and subject to AMR in accordance with 10 CFR 54.4(a)(2)
- provide the results of an evaluation that demonstrates the failure of this piping, while fluid-filled during a DBE, will not prevent the satisfactory accomplishment of any functions identified in 10 CFR 54.4(a)(1)

In its response dated February 3, 2011, the applicant stated that the 2 in. piping attached to the reactor coolant drain tank is excluded from the scope of license renewal since it contains air or gas during normal operation and would under extremely rare conditions contain drainage from the valve steam leak-off lines. The applicant stated that its assessment of the reactor coolant drain tank is consistent with its scoping methodology found in LRA Section 2.1.2.2.3, which states that nonsafety-related components containing air or gas are excluded from scope of license renewal with the exception of portions that are directly attached to safety-related components and were required for structural support. For additional justification for excluding the drain tank, the applicant referenced NUREG-1800, Section A.1 (BTP RLSP-1), which states specific aging effects from abnormal events need not be postulated for license renewal. The applicant determined that the internal environment of the 2 in. piping is air-indoor uncontrolled, and no credible aging effect could degrade the piping. However, during the April 8, 2011, teleconference between the applicant and staff, the applicant revised its position on excluding the 2 in. piping from scope of license renewal. The applicant submitted supplemental information to staff, which include the 2 in. piping within the scope of license renewal under 10 CFR 54.4(a)(2) for spatial interaction.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.45-01 acceptable because the applicant revised its position regarding the 2 in. piping to include it within the scope of license renewal under 10 CFR 54.4(a)(2) for spatial interaction. Therefore, the staff's concern described in RAI 2.3.3.45-01 is resolved.

In RAI 2.3.3.45-02, dated January 5, 2011, the staff noted on LRA drawing PID-1-WLD-LR20218, at location H-5, that the applicant depicts a relief valve tailpipe connected to relief valve V83 as not being within scope of license renewal. However, on LRA drawing PID-1-WLD-LR20219, at location F-4, the applicant depicts the tailpipe within the scope of license renewal under 10 CFR 54.4(a)(2). The applicant was asked to clarify the scoping classification for the relief valve tailpipe.

In its response dated February 3, 2011, the applicant initially stated that the relief valve tailpipe connected to relief valve V83 is not within the scope of license renewal. The applicant also indicated that LRA drawing PID-1-WLD-LR20219 erroneously depicted the relief valve tailpipe as being within the scope of license renewal. However, during the April 8, 2011, teleconference between the applicant and staff, the applicant revised its position on excluding the relief valve tailpipe from the scope of license renewal. The applicant submitted supplemental information to the staff by letter dated April 22, 2011, which included the relief valve tailpipes within the scope of license renewal under 10 CFR 54.4(a)(2) for spatial interaction.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.45-02 acceptable because the applicant revised its position regarding the relief valve tailpipe to include it within the scope of license renewal under 10 CFR 54.4(a)(2) for spatial interaction. Therefore, the staff's concern described in RAI 2.3.3.45-02 is resolved.

2.3.3.45.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the waste processing liquid drains system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the mechanical 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:

- Section 2.3.4.1, "Auxiliary Steam (AS) System"
- Section 2.3.4.2, "Auxiliary Steam Condensate (ASC) System"
- Section 2.3.4.3, "Auxiliary Steam Heating (ASH) System"
- Section 2.3.4.4, "Circulating Water (CW) System"
- Section 2.3.4.5, "Condensate (CO) System"
- Section 2.3.4.6, "Feedwater (FW) System"
- Section 2.3.4.7, "Main Steam (MS) System (Includes Main Steam Drain System)"
- Section 2.3.4.8, "Steam Generator Blowdown (SB) System"

The staff's findings on review of LRA Sections 2.3.4.1–2.3.4.8 are in provided in SER Sections 2.3.4.1–2.3.4.8, respectively.

2.3.4.1 Auxiliary Steam System

2.3.4.1.1 Summary of Technical Information in the Application

The auxiliary steam system is comprised of the following equipment:

- two package boilers, each rated at 80,000 pounds (lb) per hour of saturated steam at 150 psig, complete with forced draft fans, breeching and common stack
- one 170,000 lb per hour de-aerating heater with storage tank
- three motor-driven boiler feed pumps rated at 180 gpm each (one spare)
- triplex fuel oil pumping set (one spare pump)
- one blowdown tank, one fuel oil storage tank, and two skid-mounted chemical feed units
- interconnecting piping
- safety-related primary auxiliary building isolation valves

During plant start-up, excess condensate from auxiliary steam used for turbine gland sealing and shell warming is returned to the auxiliary steam condensate system.

Feedwater from the de-aerator is pumped to the auxiliary boilers and evaporated. Steam is piped to building heating units and operating equipment. Building heating system condensate and the equipment steam or drains, or both, are added to the main cycle or returned to the auxiliary boiler de-aerator.

The boilers are fired by No. 2 fuel oil. Steam atomization is used during normal boiler operation. Air is the atomizing medium for startup.

During normal plant operation, a branch line from main steam system lines can supply the required steam to the auxiliary steam system. A pressure-reducing valve reduces the main steam pressure to that equivalent to the output of the auxiliary boilers. The pressure-reducing station is closed during station startup, when the auxiliary boilers furnish the required steam. The auxiliary steam primary auxiliary building isolation valves are operable from the main control board and close automatically on an HELB signal.

2.3.4.1.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the auxiliary steam system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the auxiliary steam system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.2 Auxiliary Steam Condensate System

2.3.4.2.1 Summary of Technical Information in the Application

The auxiliary steam condensate system is part of the auxiliary steam system, as described in UFSAR Section 10.4.11.

During plant start-up, excess condensate from auxiliary steam—used for turbine gland sealing and shell warming—is returned to the auxiliary steam condensate system. During normal operation, building heating system condensate and the equipment steam or drains, or both, are added to the main cycle or returned to the auxiliary boiler de-aerator. In the event that any of the systems being supplied with auxiliary steam become contaminated, the auxiliary condensate will, in turn, become contaminated. To prevent the auxiliary boiler from becoming contaminated, the unit is equipped with a radiation monitor, which samples the condensate in the condensate return line. If the radionuclide concentration exceeds a pre-selected level, the monitor automatically terminates the condensate return.

2.3.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2, UFSAR Section 10.4.11, 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. In addition to the continuation issue identified in RAI 2.3-01 described in Section 2.3.3, the staff's review identified an area in which additional information was required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI, as discussed below.

In RAI 2.3.4.2-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-ASC-LR20908, at location E-12, that the applicant depicts piping inside heat exchanger HWS-E-132 within the scope of license renewal under 10 CFR 54.4(a)(2). However, on LRA drawing PID-1-HW-LR20056, at location F-11, the applicant depicts the same piping for the heat exchanger HWS-E-132 not within scope of license renewal. The applicant was asked to clarify the scoping of the piping inside the heat exchanger HWS-E-132.

In its response dated February 3, 2011, the applicant stated the piping (or tubing) inside the heat exchanger HWS-E-132 is excluded from within the scope of license renewal. The applicant also indicated that the LRA drawing erroneously depicted the tubing as being within scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.2-01 acceptable because the applicant clarified that the piping inside the heat exchanger is not in the scope of license renewal. The staff confirmed this to be acceptable by reviewing LRA Section 2.3.3.19, "Hot Water Heating System," and confirming that the heat exchanger is in-scope for pressure boundary and the tubing inside the heat exchanger was not listed in the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.4.2-01 is resolved.

2.3.4.2.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the auxiliary steam condensate system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.3 Auxiliary Steam Heating System

2.3.4.3.1 Summary of Technical Information in the Application

The auxiliary steam heating system provides low–pressure, saturated steam to various plant equipment and buildings for heating purposes.

2.3.4.3.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the auxiliary steam heating system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the auxiliary steam heating system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.4 Circulating Water System

2.3.4.4.1 Summary of Technical Information in the Application

The circulating water system provides cooling water to the main condensers to remove the heat rejected by the turbine cycle and auxiliary systems. The design of the system also includes the capability for furnishing cooling water to the service water system, and returning it to the circulating water discharge flow. Cooling and lubricating water for the circulating water pumps and motors is provided by the discharge of the operating pumps. On the startup of the first circulating water pump, the service water screen wash system pump provides the water source.

2.3.4.4.2 Conclusion

Based on the results of the staff evaluation discussed in Section 2.3 and on a review of the LRA, UFSAR, and license renewal boundary drawings the staff concluded that the applicant appropriately identified the circulating water system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the circulating water system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.5 Condensate System

2.3.4.5.1 Summary of Technical Information in the Application

The condensate system, in conjunction with the feedwater system, returns the condensate from the turbine condenser hotwells through the regenerative feed heating cycle to the steam generators while maintaining the water inventories throughout the cycle.

Three motor-driven, constant-speed, vertical canned-type condensate pumps withdraw condensate from the three condenser hotwells. During normal operation, only two pumps will be operating, and one will be on standby. Seal and priming water are supplied to the condensate pumps from the condensate storage tank or the demineralized water system. The condensate pumps discharge into a common header that carries the flow to the steam packing exhauster, which condenses the turbine sealing steam and exhausts noncondensibles through blowers to the atmosphere. The common condensate header distributes the flow equally to the suction side of the two steam generator feed pumps.

Condenser hot well makeup is provided from either the condensate storage tank or the demineralized water storage tanks upon receipt of a hotwell low-level signal. The condensate storage tank is protected from freezing by a recirculation system, which uses a heat exchanger and pump controlled by tank temperature. All condensate system connections to the condensate storage tank, which are required for normal system operation, are located above the tank level required for emergency plant shutdown. The bottom half of the tank (212,000 gal.) is used only for emergency plant shutdown and cooldown by the emergency feedwater pumps. The EFW system is evaluated under the feedwater system.

A steam generator startup feed pump provides normal requirements for startup, cooldown, and no-load operation. The pump takes suction from the condensate storage tank and discharges through a startup heater into the high pressure feedwater heater discharge piping. The startup feedwater system is evaluated under the feedwater system. The condensate pumps can also be used for startup by using the steam generator feedwater pump bypass piping.

2.3.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.5, UFSAR Sections 6.8.2, 9.2.6, 10.4.7, UFSAR Table 7.4-1, 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 required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI, as discussed below.

In RAI 2.3.4.5-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-CO-LR20426, at location H-9, that the applicant depicts a floating seal in the condensate storage tank as not being within scope of license renewal. However, LRA Table 2.3.4-5 does not list this floating seal. The staff's position is that the floating seal appears to be part of the condensate system tank, which is depicted as being within the scope of license renewal for 10 CFR 54.4(a)(1). The applicant was asked to justify the exclusion of the floating seal from the scope of license renewal and LRA Table 2.3.4-5.

In its response dated February 3, 2011, the applicant stated the floating cover seal was included within scope of license renewal under 10 CFR 54.4(a)(2) for providing functional support for the condensate storage tank. However, the applicant excluded the floating seal from being subject to an AMR due to the floating seal being replaced every six refueling cycles.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.5-01 acceptable because the floating seal was included within scope of license renewal under 10 CFR 54.4(a)(2) due to its functional support for the condensate storage tank. The staff confirmed that the applicant's justification for exempting the floating seal from an AMR is consistent with 10 CFR 54.21(a)(1)(ii) due to the floating seal being replaced every six refueling cycles. Therefore, the staff's concern described in RAI 2.3.4.5-01 is resolved.

2.3.4.5.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the condensate system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.6 Feedwater System

2.3.4.6.1 Summary of Technical Information in the Application

The feedwater system receives water from the condensate system and a portion of the heater drain system (specifically, drains from high pressure heaters No. 6, low pressure heaters No. 5, moisture separator reheater shell drains, and moisture separator reheater drains). The feedwater is pumped through the final stage of feedwater heaters (high pressure heaters No. 6) to the four steam generators.

The four feedwater lines exit the turbine building; two routed east of the containment and two routed west, where they enter the east and west main steam and feedwater pipe chases. The east and west pipe chases house the feedwater isolation valves, which are located just upstream of the containment penetrations and connections to the steam generators. Immediately upstream of the feedwater isolation valve is a check valve and a flow measuring device. The EFW pump discharge connection to each main feedwater line is located between the containment penetration and the feedwater isolation valve.

An ultrasonic feedwater flow measurement system is installed in the common feedwater header, just upstream of the feedwater regulating valves. This system is comprised of a 36-in. in-line flow measurement spool piece and a local system processor panel. The ultrasonic flow measurement system provides high accuracy mass flow, feedwater temperature, and feedwater pressure signals to the main plant computer system via a digital communication link. These signals are used as inputs to the secondary power calorimetric calculation performed by the main plant computer system.

Each steam generator feedwater pump has a recirculation control system, which protects the pumps from damage at low loads by ensuring minimum flow. A feed pump gland seal water system regulates the flow of condensate from the condensate pump discharge header to the feed pump seals. Leak-off from the seals to the seal water receiver tank is returned to the condenser using a tank level controller, which operates a control valve in the outlet line from the tank to the condenser.

Individual steam turbines drive the steam generator feedwater pumps. The turbine drives are of the dual admission type, and each is equipped with two sets of stop and control valves. One set regulates high-pressure steam from the main steam system, and the other set regulates low-pressure steam extracted from the crossover piping. Gland steam is provided to the turbines from the main turbine gland steam supply system. The exhaust steam from the steam generator feedwater pump turbine drives is condensed in main condenser shells “A” and “C.”

One steam generator startup feed pump provides normal requirements for startup, cooldown, and no-load operation. The pump takes suction from the condensate storage tank and discharges through a startup heater into the high pressure feedwater heater discharge piping. The pump suction may also be aligned to the demineralized water storage tanks as a backup water source. Startup feedwater flow may also be directed through both high pressure feedwater heaters in series. The startup feedwater system is described in Subsection 10.4.12 of the UFSAR. The condensate pumps can also be used for startup by using the steam generator feedwater pump bypass piping. A sampling system is provided and connected to various points in the condensate, feedwater, and heater drains systems (see UFSAR Subsection 9.3.2).

Condensate and feedwater chemistry is controlled as described in UFSAR Subsection 10.3.5.

The chemical feed for the condensate and steam generator wet lay up systems is stored in covered tanks for personnel protection.

<u>EFW System</u>. Upon loss of normal feedwater flow, the reactor is tripped, and the decay and sensible heat is transferred to the steam generators by the RCS via the RCPs or by natural circulation when the pumps are not operational.

Heat is removed from the steam generators via the main condensers or the main steam safety or steam generator atmospheric relief valves. Steam generator water inventory is maintained by water makeup from the EFW system. The system will supply feedwater to the steam generators to remove sufficient heat to prevent the over-pressurization of the RCS and to allow for eventual system cooldown.

The EFW system is comprised of two full-sized pumps (one motor and one turbine driven) whose water source is the condensate storage tank. Suction lines are individually run from the condensate storage tank to each pump. A common EFW pump recirculation line discharges back to the condensate storage tank. This return line functions for recirculation pump testing and ensures minimum flow to prevent pump damage for any system low-flow operating condition. Both pumps feed a common discharge header, which, in turn, supplies the four emergency feed lines. The common discharge header includes normally open gate valves between each branch connection to provide isolation in the event of a pipe break or for maintenance. Each emergency feed line is connected to one of the main feedwater lines downstream of the feedwater isolation valve. Each main feedwater line enters the containment through a single penetration and feeds a single steam generator.

Additional redundant pumping capability is provided by the startup feed pump in the feedwater system.

A dedicated 196,000 gal. of demineralized water is maintained in the lower half of the condensate storage tank for the exclusive use of the EFW system.

The branch lines to each steam generator include a manual gate isolation valve, two motor-operated flow control valves, a flow venturi, and a flow orifice. The flow control valves are normally in the open position when the system is not operating, and they are automatically closed during system operation in the event of a pipe break. These valves can be operated remotely, as described in UFSAR Subsection 6.8.5, to control steam generator water level. Two valves in series are provided for redundancy and are powered from different trains. Each valve is also provided with a hand wheel to permit manual operation. The open position of the flow control valves for system limiting conditions is set to insure the minimum required flow of 470 gpm to three steam generators and a minimum total flow of 650 gpm to four steam generators with one EFW pump operational.

2.3.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.6, UFSAR Sections 6.8, 9.3.2, 10.3.5, 10.4.7, 10.4.12, UFSAR Tables 7.4-1, 7.5-1, and 6.2-83, 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 required to complete the review of the applicant's scoping and screening results. The staff addressed the applicant's response to RAI 2.3-01 in Section 2.3.3 of this SER. The staff did not identify any other additional concerns with the applicant's scoping and screening of feedwater system components for license renewal.

2.3.4.6.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant 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 all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.7 Main Steam System (Includes Main Steam Drain System)

2.3.4.7.1 Summary of Technical Information in the Application

The major function of the main steam system is to transport the steam generated in the four steam generators to the turbine generator for conversion to electrical power. Heat transferred from the reactor core to the RCS is subsequently transferred across the steam generator U-tubes for conversion of secondary feedwater into main steam.

This steam passes through a moisture separator and a flow restrictor as it leaves the steam generator and enters its main steam header. The moisture separator improves steam quality, while the flow restrictor prevents excessive steam flow in the event of an unisolable steam line rupture.

2.3.4.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.7, UFSAR Section 10.3, UFSAR Tables 6.2-83, 7.4-1, and 7.5-1, 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 required to complete the review of the applicant's scoping and screening results. The staff addressed the applicant's response to RAI 2.3-01 in Section 2.3.3 of this SER. The staff did not identify any other additional concerns with the applicant's scoping and screening of main steam system components for license renewal.

2.3.4.7.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant 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 all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.8 Steam Generator Blowdown System

2.3.4.8.1 Summary of Technical Information in the Application

Each of the four steam generators is provided with a bottom blow down connection on the secondary side above the tube sheet. During normal operation, each steam generator undergoes continuous blowdown with the blowdown water passing through a containment isolation valve, flow meter, and system valves. A small quantity of blowdown is continuously drawn off automatically into the sample system through a sample heat exchanger for monitoring of the activity in the blowdown. If the activity in the blow down discharge is higher than allowable, blowdown is automatically secured. The blowdown liquid then flows through a manual control valve, which establishes the blowdown rate. Some of the liquid flashes upon passing through the control valve, and two-phase flow then enters the flash tank. There, approximately 30 percent of the blowdown flow exits the top of the tank as saturated steam. The remaining 70 percent exits the bottom of the tank as saturated water.

2.3.4.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.8, UFSAR Section 10.4.8, UFSAR Tables 6.2-83, 7.4-1, and 7.5-1, 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. In addition to the continuation issue identified in RAI 2.3-01 described in Section 2.3.3, the staff's review identified an area in which additional information was required to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI, as discussed below.

In RAI 2.3.4.8-01, dated January 5, 2011, the staff noted on LRA drawing PID-1-SS-LR20521, at location A-6, that the applicant depicts cooler H-376 as being within scope of license renewal under 10 CFR 54.4(a)(2). However, the applicant excludes the "vent to atmosphere" piping, which is attached to cooler H-376, from the scope of license renewal. The applicant was asked to justify its exclusion of the "vent to atmosphere" piping from the scope of license renewal.

In its response dated February 3, 2011, the applicant stated the "vent to atmosphere" piping is within scope of license renewal under 10 CFR 54.4(a)(2). The applicant also stated that LRA drawing PID-1-SS-LR20521 erroneously depicted the "vent to atmosphere" piping as being excluded from scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.8-01 acceptable because the "vent to atmosphere" piping was already included within the scope of license renewal under 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.4.8-01 is resolved.

2.3.4.8.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses, and license renewal boundary drawings to determine whether the applicant had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the steam generator blowdown system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the mechanical 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 discusses the reactor building and other Class I and in-scope structures.

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 confirm that there were no omissions of SCs that meet the scoping criteria and are subject to an AMR.

The staff's evaluation of the information in the LRA was the same for all structures. The objective was to determine if the applicant identified, in accordance with 10 CFR 54.4, components and supporting structures for structures that appear to meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to verify that all passive, long-lived SCs were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its scoping evaluation, the staff reviewed the applicable LRA sections, focusing on components that have not been identified as within the scope of license renewal. The staff reviewed relevant licensing basis documents, including the UFSAR, for each structure to determine if the applicant omitted from the scope of license renewal components with intended functions delineated under 10 CFR 54.4(a). The staff also reviewed the licensing basis documents to determine if the LRA specified all intended functions delineated under 10 CFR 54.4(a). The staff requested additional information to resolve any omissions or discrepancies identified.

After its review of the scoping results, the staff evaluated the applicant's screening results. For those SCs with safety-related intended functions, the staff sought to determine if the functions are performed with moving parts or a change in configuration or properties or if the SCs are subject to replacement after a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those meeting neither of these criteria, the staff sought to confirm that these SCs were subject to an AMR, as required by 10 CFR 54.21(a)(1). The staff requested additional information to resolve any omissions or discrepancies identified.

2.4.1 Buildings, Structures within License Renewal

2.4.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.1, the applicant described the buildings and structures within license renewal as being NNS-related, miscellaneous buildings that could prevent satisfactory accomplishment of a safety-related 10 CFR 54.4(a)(1) function. In addition, these structures and buildings may house equipment for any of the 10 CFR 54.4(a)(3) regulated events. The following structures are described in LRA Section 2.4.1.

<u>Discharge Transition Structure</u>. This Non-Seismic Category I structure provides a path to discharge cooling water from the condenser through the discharge tunnel and into to the ocean, during normal operation. The structure is also aligned to provide water from the discharge tunnel to the service water pumphouse and the circulating water pumphouse if necessary.

<u>Fire Pumphouse (including Fire Protection Water Storage Tanks (foundations only), Fire Pumphouse Boiler Building, Boiler Fuel Tank (foundation and steel framing only), and two Fuel Oil Day Tanks (foundations and steel framing only)</u>. The fire pumphouse is a non-seismic Category I structure that houses electric and diesel-driven fire pumps and associated controls. The two 500,000 gal. fire protection water storage tanks are non-seismic Category I structures. The fire pumphouse boiler building and boiler fuel tank are non-seismic Category I structures. The purpose of the boiler is to provide heat to the fire pumphouse. In addition, two Fuel oil day tanks provide diesel fuel to the two diesel-driven fire pumps.

<u>Intake Transition Structure</u>. This non-seismic Category I structure provides seawater to the service water pumphouse and the circulating water pumphouse from the ocean and intake tunnel. In addition, it serves as a surge chamber that stabilizes changing water levels.

<u>Non-Essential Switchgear Building</u>. This non-seismic Category I structure houses Appendix R emergency lighting needed for operation of safe shutdown equipment and for access and egress routes thereto. In addition, it houses and protects the electrical equipment used to provide lighting for the plant.

Revetment. The revetment structures are classified as non-seismic Category I and provide flood protection to safety-related structures from a predicted probable maximum hurricane (PMH) surge by means of a protective retaining wall, a vertical seawall, and revetment (riprap).

Steam Generator Blowdown Recovery Building. The steam generator blowdown recovery building is a non-seismic Category I structure and houses the steam generator blowdown recovery system. The loss of function of these systems and components will not affect the capability of a safe reactor shutdown.

LRA Table 2.4-1 identifies the components subject to an AMR, for the buildings and structures within license renewal, by component type and intended function.

2.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1 and the UFSAR using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

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

During its review of LRA Section 2.4, the staff noted areas in which additional information was necessary to complete its review of the applicant's scoping and screening results. Specifically, the staff noted that there were no trash racks, basket strainers, traveling screens, or any other debris prevention or removing mechanisms listed as part of the intake transition structure. By letter dated November 18, 2010, the staff issued RAI 2.4.1-1, requesting that the applicant verify if the aforementioned components are present and within the scope of license renewal of the identified structure and, thus, subject to an AMR. In addition, if they are subject to an AMR, the staff asked that the applicant identify the applicable aging effects and the AMP related to these components.

By letter dated December 3, 2010, the applicant responded to RAI 2.4.1-1 and stated the following:

> There, are no structural components such as trash racks, basket strainers, traveling screens or any other debris prevention/removing mechanisms that are part of the Intake Transition Structure.
>
> There is a Chlorination System (CL) Strainer, 1-CL-S-256, which is located in a pit, adjacent to the Intake Transition Structure that is in scope for license renewal. Being non-metallic and having no reported aging effects, the strainer does not require an aging management program.
>
> The Service Water Pumphouse does contain traveling screens. These were screened out of License Renewal as being active components, except for the covering shrouds, which are in-scope with an (a)(2) intended function of protecting safety related equipment from raw water spray. The shrouds are fiberglass, with no aging effects, and are not age managed.

> Located in the Primary Auxiliary Building, a basket-type strainer is provided in each train of the, Service Water System to prevent shells and mussels, which could be carried into these lines, from fouling various heat exchangers. These strainers are within the scope of License Renewal and are age managed as part of the Open Cycle Cooling Water Aging Management Program.

In reviewing the applicant's response to RAI 2.4.1-1, the staff found that the applicant adequately clarified the location of the trash racks, basket strainers, traveling screens, or any other debris prevention or removing mechanisms present. Additionally, for those present and within the scope of license renewal, an AMP was in place to manage the age effects of the component. Based on its review, the staff finds the applicant's response to RAI 2.4.1-1 acceptable because it clarified that there are no trash racks, basket strainers, traveling screens, or any other debris prevention or removing mechanisms in the intake transition structure within the scope of license renewal and subject to an AMR. The staff's concern described in RAI 2.4.1-1 is resolved.

By letter dated November 18, 2010, the staff issued RAI 2.4.1-2, requesting that the applicant clarify if the following components listed below, which are credited for flood protection per UFSAR Section 3.4.1.1, would be required to be included within the scope of license renewal:

- rolling steel door in the fuel storage building (elevation 20 ft 6 in. mean sea level (MSL))
- double doors into the entrance vestibule of the Equipment vault section of the primary auxiliary building (elevation 20 ft 8 in. MSL)

For those components that should be included within the scope of license renewal, the staff also asked the applicant to detail the applicable aging effects and the appropriate AMP related to the component.

By letter dated December 3, 2010, the applicant responded to RAI 2.4.1-2 and stated, in part, that "[f]lood protection for the Fuel Storage Building is provided by a curb at elevation 21.5 ft MSL located on column 3 behind the rolling steel door…"

The floor of the vestibule into the Equipment Vault section of the Primary Auxiliary Building is sloped up 4 inches so that the high point in the floor is at elevation 21 ft MSL.

Both doors are in scope of license renewal for other intended functions other than flood protection. The Fuel Storage Building rollup door is included in the generic component Primary Structures (PST)-Carbon Steel Door-Fuel Storage Building in LRA Table 3.5.2-5 and the double doors into the Equipment Vault are included in the generic component PST-Carbon Steel Door-Primary Auxiliary Building in LRA Table 3.5.2-5.

In reviewing the applicant's response to RAI 2.4.1-2, the staff found that the applicant clarified the inclusion of the following components from the scope of license renewal:

- rolling steel door in the fuel storage building (elevation 20 ft 6 in. MSL)
- double doors into the entrance vestibule of the Equipment vault section of the primary auxiliary building (elevation 20 ft 8 in. MSL)

Both doors are within the scope of license renewal for intended functions other than flood protection, and the applicant adequately described the flood protection mechanisms for the two access openings in the exterior wall that are below the design flood level. Based on its review, the staff finds the applicant’s response to RAI 2.4.1-2 acceptable because it clarified that the rolling steel door in the fuel storage building and the double doors into the entrance vestibule of the equipment vault section of the primary auxiliary building are not credited for flood protection. However, they are included in the scope of license renewal for other intended functions. Therefore, the staff’s concern described in RAI 2.4.1-2 is resolved.

By letter dated November 18, 2010, the staff issued RAI 2.4.1-3, asking that the applicant provide additional information regarding the fire protection water storage tanks. Specifically, the staff sought to determine if there was any steel framing that was part of the structural arrangement of the tanks, since only the foundation was included in the scope of license renewal.

By letter dated December 3, 2010, the applicant responded to RAI 2.4.1-3 and stated that the fire protection water storage tanks are bolted to the tanks’ foundation, are free-standing, and have no supports.

In reviewing the applicant’s response to RAI 2.4.1-3, the staff found that the applicant clarified the structural configuration of the fire protection water storage tanks since they are free-standing and have no structural steel framing. Based on its review, the staff finds the applicant’s response to RAI 2.4.1-3 acceptable because the structural configuration of the fire protection water storage tanks has been included in the scope of license renewal and subsequent AMP. The staff’s concern described in RAI 2.4.1-3 is resolved

2.4.1.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response, to determine whether the applicant had identified all SCs within the scope of license renewal. In addition, the staff’s review determined whether the applicant had identified all SCs subject to an AMR. On the basis of its review, the staff concludes the applicant has adequately identified the buildings and structures SCs 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).

2.4.2 Containment Structures

2.4.2.1 Summary of Technical Information in the Application

In LRA Section 2.4.2, the applicant described the containment structures as seismic Category I structures that enclose and provide physical support and protection to the RCS. The containment structures consist of the following structures.

<u>Containment Structure</u>. This reinforced concrete containment structure completely encloses the RCS and has the form of a right vertical cylinder with a hemispherical dome and a flat foundation mat founded on bedrock. The inside face is lined with a welded carbon steel plate that provides a high degree of leak tightness. Containment penetrations are provided in the lower portion and consist of a personnel lock, an equipment hatch and personnel lock, a fuel transfer tube and piping, electrical, instrumentation, and ventilation penetrations. All penetrations are anchored to sleeves embedded in the concrete wall.

<u>Containment Enclosure Building</u>. This reinforced concrete containment enclosure building surrounds the containment structure and is designed in a similar configuration as a vertical right cylinder with a dome and a ring base. The structure is designed to entrap, filter, and then

discharge any leakage from the containment structure. The containment enclosure building provides the secondary containment barrier.

Containment Enclosure and Ventilation Area. This reinforced concrete structure is an irregularly shaped building that houses ventilation equipment such as fans and filters for the enclosure building. It is physically located on the southwest side of the containment.

Containment Internals. The containment internals consist of intermediate floor slabs, internal walls, steel framing, and other support appurtenances. The purpose of the containment internal structures is to provide structural support for safety and nonsafety-related equipment, shielding, and HELB protection.

LRA Table 2.4-2 identifies the components, subject to an AMR for the containment structures within license renewal, by component type and intended function.

2.4.2.2 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant had identified all SCs within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all SCs subject to an AMR. On the basis of its review, the staff concludes that the applicant has adequately identified the containment structures SCs 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).

2.4.3 Fuel Handling and Overhead Cranes

2.4.3.1 Summary of Technical Information in the Application

In LRA Section 2.4.3, the applicant described the fuel handling and overhead cranes as consisting of overhead heavy load cranes encompassed by NUREG-0612 and light load cranes related to refueling handling systems. These systems are associated with reactor vessel assembly, fuel movement, spent fuel cask, and other overhead lifting activities that could have an effect on safe shutdown equipment or fuel integrity or both. LRA Table 2.4-3 identifies the components subject to an AMR for the fuel handling and overhead cranes by component type and intended function.

2.4.3.2 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant had identified all SCs within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all SCs subject to an AMR. On the basis of its review, the staff concludes that the applicant has adequately identified the fuel handling and overhead cranes SCs 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).

2.4.4 Miscellaneous Yard Structures

2.4.4.1 Summary of Technical Information in the Application

In LRA Section 2.4.4, the applicant described the miscellaneous yard structures as non-building structures that are exposed to an outdoor environment. These structures include buried vaults, duct banks and manholes, the condensate storage tank enclosure, and SBO structures. They are described below in more detail.

Condensate Storage Tank Enclosure. The seismic Category I enclosure consists of a cylindrical reinforced concrete wall that surrounds the condensate storage tank. In addition, two irregularly shaped rooms—north and south valve rooms—are integral with the circular wall.

Control Room Makeup Air Intake Structures. The seismic Category I air intake structures serve as terminals for buried ductwork that provide air for the control rooms during accident conditions.

Nonsafety-Related Electrical Duct Banks and Manholes. The reinforced concrete manholes and nonsafety-related electrical duct banks house select cables that support fire pump 1-FP-P21.

Safety-Related Electrical Duct Banks and Manholes. The safety-related electrical duct banks and manholes are made of reinforced concrete and are isolated by seismic joints.

Service Water Access Vault. The seismic Category I service water access vault is physically located underground north of the plant's cooling towers. This structure provides access to 24 in. service water piping.

Yard Structures that Support Coping with SBO. The yard structures are described as providing equipment enclosure and structural support that ultimately supports SCs coping with an SBO event.

LRA Table 2.4-4 identifies the components, subject to an AMR for the miscellaneous yard structures within license renewal, by component type and intended function.

2.4.4.2 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant had identified all SCs within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all SCs subject to an AMR. On the basis of its review, the staff concludes that the applicant has adequately identified the miscellaneous yard structures SCs 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).

2.4.5 Primary Structures

2.4.5.1 Summary of Technical Information in the Application

In LRA Section 2.4.5, the applicant described the primary structures as being seismic Category I structures that are not part of the containment structures or water control structures. They consist of the following structures.

Containment Equipment Hatch Missile Shield. This structure consists of a removable, precast, reinforced concrete wall physically located outside the equipment hatch. The shield protects the hatch from tornado-generated missiles.

Control Building and Diesel Generator Building. This structure is separated by a common wall in the north-south direction and is made of reinforced concrete founded on fill concrete and rock below grade. The multi-function structure consists of the east portion occupied by the control room and the west portion occupied by the diesel generator building.

EFPH including Electrical Cable Tunnels and Penetration Area (Control Building to Containment) and Pre-Action Valve Building. The EFPH is physically located adjacent to the containment structure and consists of the EFW pump room located above a two-story high electrical cable tray tunnel. The pre-action valve room contains the deluge valve for the fire protection system and is located on the east side of the EFW building.

Fuel Storage Building. The spent fuel pool and storage facility consists of four main areas—the spent fuel pool, the fuel transfer canal, the spent fuel cask loading area, and a decontamination area. The spent fuel pool is constructed of reinforced concrete, with all interior surfaces lined with stainless steel.

Main Steam and Feedwater Pipe Chases-East and West. The main steam and feedwater pipe chase (east and west) are reinforced structures that house and protect the main steam and feedwater piping.

Personnel Hatch Area. The personnel hatch area is an irregularly shaped, reinforced concrete area that is physically located outside the personnel hatch of the containment and provides protection from missiles and illegal entry.

Primary Auxiliary Building including RHR Equipment Vault. The auxiliary building is a reinforced concrete structure that is physically located adjacent to the containment structure. The building houses most of the auxiliary systems for the RCS. In addition, it houses components essential for safe shutdown which could be subject to the effects of an HELB.

Tank Farm (Tunnels)—Including Dikes and Foundations for RWST and Reactor Makeup Water Storage Tank. The tank farm areas consist of a reinforced concrete portion and structural steel framing portion. The reinforced portion is associated with safety-related systems, and the steel portion is used to enclose the area above the tanks and to form the motor control center and switchgear room.

Waste Process Building. The waste process building is a reinforced concrete structure that houses the liquid and gas waste processing, boron recovery, and solid waste systems. The building contains systems to process radioactive gases, liquids and solids.

LRA Table 2.4-5 identifies the components, subject to an AMR for the PSTs within license renewal, by component type and intended function.

2.4.5.2 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant had identified all SCs within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all SCs subject to an AMR. On the basis of its review, the staff concludes that the applicant has adequately identified the PSTs SCs 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).

2.4.6 Supports

2.4.6.1 Summary of Technical Information in the Application

In LRA Section 2.4.6, the applicant described the supports commodity as including ASME and non-ASME pipe restraints and supports, jet impingement barriers and shields, pipe whip restraints, supports for tube tracks, instrument tubing, miscellaneous mechanical equipment, electrical raceways and conduit, HVAC ducts, racks, panels, cabinets, enclosures for electrical equipment, junction boxes, platforms, grout under base plates, fasteners and anchorage, instruments and battery racks, support base plate pads, etc. Supports provide the connection between a system's equipment or component and a plant structural member, such as a wall, beam, or column.

LRA Table 2.4-6 identifies the components, subject to an AMR for the supports commodity within license renewal, by component type and intended function.

2.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.4.6 and the UFSAR using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

During its review, the staff evaluated the structural component functions described in the LRA and UFSAR to verify that the applicant has not omitted from the scope of license renewal any SCs with intended functions delineated under 10 CFR 54.4(a).

The staff then reviewed those SCs that the applicant included as within the scope of license renewal to verify that the applicant has not omitted any passive and long-lived SCs subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

During its review of LRA Section 2.6, the staff noted areas in which additional information was necessary to complete its review of the applicant's scoping and screening results. By letter dated November 18, 2010, the staff issued RAI 2.4.6-1, requesting that the applicant confirm the inclusion of the structural bellows in the scope of license renewal, as applicable, and subject to an AMR, per 10 CFR 54.21(a)(1)(i), and provide the location in the LRA where they are covered. In addition, in the event that the structural bellows were omitted, the staff asked the applicant to justify the exclusion from scope of license renewal.

By letter dated December 3, 2010, the applicant responded to RAI 2.4.6-1 and stated, in part, the following:

> There are three structural bellows at Seabrook Station and all are associated with the fuel transfer tube between the fuel storage building and the containment structure. All three bellows are in scope of LR. One bellow in the fuel storage building is in scope as part of the fuel transfer tube component in the primary structures (Table 3.5.2-5) and the other two bellows in the containment structure are located with the fuel transfer tube component in the containment structure (Table 3.5.2-2).

In reviewing its response to RAI 2.4.6-1, the staff found that the applicant verified the inclusion of all structural bellows within the scope of LR. In addition, the response also clarified the location within the LRA where the components were covered. Based on its review, the staff finds the applicant's response to RAI 2.4.6-1 acceptable because the structural bellows at

Seabrook have been included in the scope of license renewal and subsequent AMP. The staff's concern described in RAI 2.4.6-1 is resolved.

By letter dated November 18, 2010, the staff issued RAI 2.4.6-2, requesting that the applicant clarify a potential discrepancy regarding the neutron absorbent material attached to the spent fuel pool racks. Specifically, LRA Section 2.4.6 states that "BORAFLEX utilized in region 2 racks is not credited with the neutron-absorbing capacity in the criticality analyses and therefore will not be managed for reduction of neutron absorbing capacity in the criticality analyses…" However, UFSAR Section 9.1.2.1 states that the "Region 2 Spent Fuel Racks contain BORAFLEX as a neutron absorbing material to assure a Keff<0.95." In addition, the staff asked that the applicant clearly state the inclusion, or justify the exclusion, of the BORAFLEX from the scope of license renewal and subject to an AMR.

By letter dated December 3, 2010, the applicant responded to RAI 2.4.6-2 and stated, in part, the following:

> An UFSAR change request has been issued to correct the inconsistency. The revised UFSAR will state that the BORAFLEX material is conservatively assumed to be neutron transparent based on industry experience of BORAFLEX degradation.

In reviewing the applicant's response to RAI 2.4.6-2, the staff found that the applicant is aware of the inconsistency between references and has submitted a change request to reflect that BORAFLEX material will be conservatively assumed to be neutron transparent.

Based on its review, the staff finds the applicant's response to RAI 2.4.6-2 acceptable because the inconsistency between references has been clarified. Therefore, the staff's concern described in RAI 2.4.6-2 is resolved.

2.4.6.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response, to determine whether the applicant had identified all SCs within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all SCs subject to an AMR. On the basis of its review, the staff concludes that the applicant has adequately identified the supports SCs 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).

2.4.7 Turbine Building

2.4.7.1 Summary of Technical Information in the Application

In LRA Section 2.4.7, the applicant described the turbine building as a non-seismic Category I structure that houses the turbine generator and the associated condensers, pumps, and feedwater heaters. In addition, the structure also houses the lube oil, secondary component cooling, and service and instrument air systems. The structure does not support any safety-related function per 10 CFR 54.4(a)(1). The structure only supports 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3) functions.

LRA Table 2.4-7 identifies the components, subject to an AMR for the turbine building SCs within license renewal, by component type and intended function.

2.4.7.2 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant had identified all SCs within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all SCs subject to an AMR. On the basis of its review, the staff concludes that the applicant has adequately identified the turbine building SCs 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).

2.4.8 Water Control Structures

2.4.8.1 Summary of Technical Information in the Application

In LRA Section 2.4.8, the applicant described the water control structures as those structures used for cooling water for the ultimate heat sink. They consist of the structures described below.

Service Water Cooling Tower. The service water cooling tower is categorized as a seismic Category I structure, and it is composed of a concrete basin, pump rooms, electrical switchgear rooms, and mechanical equipment rooms.

Service Water Pumphouse. The service water pumphouse is categorized as a seismic Category I structure, and it contains the four service water pumps, which are available for normal operation and for post-accident cooldown. The structure is physically adjacent to the circulating water pumphouse.

Circulating Water Pumphouse. The circulating water pumphouse is categorized as a seismic Category I structure composed of a forebay and three bays with a circulating pump in each bay. Each pump bay has one traveling screen. The three pumps located in each bay supply cooling water to the condensers.

LRA Table 2.4-8 identifies the components, subject to an AMR for the water control structures SCs within license renewal, by component type and intended function.

2.4.8.2 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant had identified all SCs within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all SCs subject to an AMR. On the basis of its review, the staff concludes that the applicant has adequately identified the water control structures SCs 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).

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

This section documents the staff's review of the applicant's scoping and screening results for electrical and I&C 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 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 in the LRA was the same for all electrical and I&C systems. The objective was to determine if the applicant has identified, in accordance with 10 CFR 54.4, components and supporting structures for electrical and I&C systems that appear to meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to verify that all passive, long-lived components were subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

In its scoping evaluation, the staff reviewed the applicable LRA sections, focusing on components that have not been identified as within the scope of license renewal. The staff reviewed relevant licensing basis documents, including the UFSAR, for each electrical and I&C system to determine if the applicant omitted from the scope of license renewal components with intended functions delineated under 10 CFR 54.4(a). The staff also reviewed the licensing basis documents to determine if the LRA specified all intended functions delineated under 10 CFR 54.4(a). The staff requested additional information to resolve any omissions or discrepancies identified.

After its review of the scoping results, the staff evaluated the applicant's screening results. For those SCs with intended functions, the staff sought to determine if the functions are performed with moving parts or a change in configuration or properties or if the SCs are subject to replacement after a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those meeting neither of these criteria, the staff sought to confirm that these SCs were subject to an AMR, as required by 10 CFR 54.21(a)(1). The staff requested additional information to resolve any omissions or discrepancies identified.

2.5.1 Electrical Component 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 considers all electrical and I&C systems including components in the recovery path for loss of offsite power in the event of an SBO. The plant-wide 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.

This approach groups all electrical and I&C components in commodity groups and identifies those electrical commodity groups that are subject to an AMR by applying the criteria of 10 CFR 54.21(a)(1). Electrical components in the SBO recovery path are identified based on their intended function. Components interfacing with the electrical and I&C components are assessed in the appropriate mechanical or structural sections. LRA Table 2.5.4-1 identifies the following component and commodity types and their intended functions within the scope of license renewal and subject to an AMR:

- non-EQ electrical cables and connections—electrical continuity
- metal enclosed bus—electrical continuity, insulation-electrical
- fuse holders (not part of a larger assembly) metallic clamp—electrical continuity
- cable connections (metallic parts)—electrical continuity

- SF_6 insulated bus, connections and insulators—electrical continuity, insulation-electrical

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 delineated under 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).

GDC 17 of 10 CFR Part 50, Appendix A, requires that electric power from the transmission network to the onsite electric distribution system is supplied by two physically independent circuits to minimize the likelihood of their simultaneous failure. In addition, the staff noted the guidance provided by letter dated April 1, 2002 (Agencywide Document Access Management System (ADAMS) Accession No. ML020920464), "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))," and later incorporated in SRP-LR Section 2.5.2.1.1

For purposes of the license renewal rule, the staff determined that the plant system portion of the offsite power system, which 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 the switchyard 345 kV power circuit breakers connecting to the generator step up (GSU) transformer, the unit auxiliary transformers (UATs), and the reserve auxiliary transformers (RATs) that are within the scope of license renewal. The circuit from the 345 kV power circuit breakers—through the UATs to the diesel-backed 4,160 volt (V) emergency buses—includes the SF_6 bus from the 345 kV power circuit breakers to the GSU transformer, the isolated phase bus from the GSU to the UATs, and the non-segregated bus from the UATs to the 4,160 V Buses E5 (EDE-SWG-5) and E6 (EDE-SWG-6). The circuit from the 345 kV power circuit breakers—through the RAT to the diesel-backed 4,160 V emergency buses—includes the SF_6 bus from the 345 kV power circuit breakers to the RATs and the non-segregated bus from the RATs to the 4,160 V Buses E5 (EDE-SWG-5) and E6 (EDE-SWG-6). 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.

The applicant did not include cable tie wraps in the commodity groups subject to an AMR because, based on a review, the applicant concluded that cable tie wraps would not prevent in-scope electrical conductors from performing their intended function. The staff reviewed the UFSAR and found that cable tie wraps are not credited in Seabrook's design basis. Therefore, the staff concludes that the exclusion of cable tie wraps from the commodity groups subject to an AMR is acceptable.

2.5.1.3 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant had identified all SCs within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all SCs subject to an AMR. On the basis of its review, the staff concludes that the applicant has adequately identified the electrical and I&C systems 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).

2.6 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 concluded that the applicant 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).

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 Seabrook Station Unit 1 (Seabrook). The evaluation is performed by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff).

In Appendix B of its license renewal application (LRA), NextEra Energy Seabrook, LLC (NextEra) (the applicant) described the 42 AMPs that it relies on to manage or monitor the aging of passive, 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, Revision 1, "Generic Aging Lessons Learned (GALL) Report," 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 license renewal SCs. 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 its programs correspond to those reviewed and approved in the report.

The purpose of the GALL Report is to provide 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 for LRA review will be greatly reduced, improving the efficiency and effectiveness of the license renewal review process. The GALL Report also serves as a quick reference for applicants and staff reviewers to AMPs and activities that the staff has determined will adequately manage or monitor aging during the period of extended operation.

The GALL Report identifies the following:

- systems, structures, and components (SSCs)
- SC materials
- environments to which the SCs are exposed
- aging effects of the materials and environments
- AMPs credited with managing or monitoring the aging effects
- recommendations for further applicant evaluations of aging management for certain component types

To determine whether the use of the GALL Report would improve the efficiency of LRA review, the staff conducted a demonstration of the GALL Report process in order to model the format and content of safety evaluations based on it. The results of the demonstration project confirmed that the GALL Report process will improve the efficiency and effectiveness of LRA review while maintaining the staff's focus on public health and safety. NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), dated September 2005, was prepared based on both the GALL Report model and lessons learned from the demonstration project.

The staff's review complied with Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and the guidance of the SRP-LR and the GALL Report.

In addition to its review of the LRA, the staff conducted onsite audits of selected AMPs to verify the applicant's claims of consistency with the GALL Report during the weeks of October 11, 2010, and October 18, 2010, as described in the "AMP Audit Report Regarding the Seabrook Station License Renewal Application," dated March 21, 2011. The onsite audits and reviews are designed to maximize efficiency of the staff's LRA review because the applicant can respond to questions, the staff can readily evaluate the applicant's responses, and the need for formal correspondence between the staff and the applicant is reduced.

3.0.1 Format of the License Renewal Application

The applicant submitted an application that follows the standard LRA format agreed to by the staff and the Nuclear Energy Institute (NEI) by letter dated April 7, 2003. This revised LRA format incorporates lessons learned from the staff's reviews of the previous five 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 Chapter 3 parallels that of SRP-LR Chapter 3. LRA Chapter 3 presents AMR results information in the following table types:

- Table 3.x.1 (Table 1s)—In these tables, "3" indicates the LRA section number, "x" indicates the subsection number from the GALL Report, and "1" indicates that this table type is the first in LRA Section 3.
- Table 3.x.2-y (Table 2s)—In these tables, "3" indicates the LRA section number, "x" indicates the subsection number from the GALL Report, "2" indicates that this table type is the second in LRA Section 3, and "y" indicates the system table number.

The content of the GALL Report tables and the LRA tables are essentially the same. In its LRA, the applicant modified the tables in Chapter 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 with respect to consistency with the GALL Report. In each Table 2, the applicant identified the linkage between the scoping and screening results in Chapter 2 and the AMRs in Chapter 3.

3.0.1.1 Overview of Table 1s

Each of the Tables 3.x.1 (Table 1s) provides a summary comparison of how the facility aligns with the corresponding tables of the GALL Report. These tables are essentially the same as Tables 1–6 provided in the GALL Report, Volume 1, except that the "ID" column has been replaced by an "Item Number" column, the "Type" column is removed, and the "Related Generic

Item" and "Unique Item" columns have been replaced by a "Discussion" column. The "Discussion" column is used by the applicant to provide clarifying and amplifying information. The following are examples of information that the applicant placed within this column:

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

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

3.0.1.2 Overview of Table 2s

Each of the Tables 3.x.2-y (Table 2s) provides the detailed results of the AMRs for those components identified in LRA Chapter 2 as subject to an AMR. The LRA contains a Table 2 for each of the systems or components "y" within a system grouping "x" (e.g., reactor coolant systems (RCSs), ESFs, auxiliary systems). For example, the ESFs group (3.2.2-y) contains tables specific to the containment vessel spray system, safety injection system, and residual heat removal (RHR) system. Each Table 2 consists of the following columns:

- Component Type—The first column identifies the component types, commodity groups, structural members, or subcomponents from LRA Chapter 2 that are subject to an AMR. The component types are listed in alphabetical order.
- Intended Function—The second column contains the license renewal intended functions for the listed component types. Definitions of intended functions are contained in LRA Table 2.0-1.
- Material—The third column lists the particular materials of construction for the component type.
- Environment—The fourth column lists the environment to which the component types are exposed. Internal and external service environments are indicated, and a list of these environments is provided in LRA Table 3.0-1.
- Aging Effect Requiring Management (AERM)—The fifth column lists aging effects and AERMs. As part of the AMR process, the applicant determined any AERMs for each combination of material and environment.
- AMPs—The sixth column lists the AMPs that the applicant used to manage the identified aging effects.
- GALL Report Volume 2 Line Item—The seventh column lists the GALL Report item(s) that the applicant identified as corresponding to the AMR results in the LRA. The applicant compared each combination of component type, material, environment, AERM, and AMP in LRA Table 2 to the items in the GALL Report. If there were no corresponding items in the GALL Report, the applicant indicated "None" in the column.

In this way, the applicant identified the AMR results in the LRA tables that corresponded to the items in the GALL Report tables.

- Table 1 Item—The eighth column lists the corresponding summary item number from Table 1. If the applicant identified AMR results in Table 2 that are consistent with the GALL Report, then the associated Table 3.x.1 line summary item number should be listed in Table 2. If there is no corresponding item in the GALL Report, then the eighth column indicates "None." That way, the information from the two tables can be correlated.
- Notes—The ninth column lists the corresponding notes that the applicant used to identify how the information in Table 2 aligns with the information in the GALL Report. The notes identified by letters were developed by an NEI working group to be used in LRAs. Any plant-specific notes are identified by a number and provide additional information concerning the consistency of the item with the GALL Report or other clarifying information.

3.0.2 Staff's Review Process

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

- For items that the applicant stated were consistent with the GALL Report, the staff conducted either an audit or a technical review to determine consistency.
- For items that the applicant stated were 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.
- 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 if the aging effects on SCs can be adequately managed to maintain their intended function(s) 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 Aging Management Programs

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 if the deviation was acceptable and if 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 program elements defined in SRP-LR Appendix A:

- Scope of the Program—Scope of the program should include the specific SCs subject to an AMR for license renewal.
- Preventive Actions—Preventive actions should prevent or mitigate aging degradation.
- Parameters Monitored or Inspected—Parameters monitored or inspected should be linked to the degradation of the particular SC's intended function(s).
- Detection of Aging Effects—Detection of aging effects should occur before there is a loss of SC's intended function(s). This includes aspects such as method or technique (i.e., visual, volumetric, surface inspection), frequency, sample size, data collection, and timing of new and one-time inspections to ensure timely detection of aging effects.
- Monitoring and Trending—Monitoring and trending should provide predictability of the extent of degradation as well as timely corrective or mitigative actions.
- Acceptance Criteria—Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the SC's intended function(s) are maintained under all CLB design conditions during the period of extended operation.
- Corrective Actions—Corrective actions, including root cause determination and prevention of recurrence, should be timely.
- Confirmation Process—Confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
- Administrative Controls—Administrative controls should provide for a formal review and approval process.
- 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's intended function(s) will be maintained during the period of extended operation.

Details of the staff's audit evaluation of program elements one through six and ten are documented in the AMP audit report and are summarized 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 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 3.0.5.

3.0.2.2 Review of Aging Management Review 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 the seventh column of the LRA, "NUREG-1801 Vol. 2 Item," correlate to an AMR combination as identified in the GALL Report. The staff also conducted onsite audits to verify these correlations. A "None" in the seventh column 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," refers to a number indicating the correlating row in Table 1.

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the report and for which it does not recommend further evaluation, the staff's audit and review determined if the plant-specific components of these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant noted, for each AMR item, how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A–E, indicating how the AMR is consistent with the GALL Report.

Note A indicates that the AMR 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 items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR 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 audited these items to verify consistency with the GALL Report and confirmed that the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined if the applicant's AMP was consistent with the GALL Report AMP and if the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR item, although different from the component identified in the GALL Report, is consistent with the GALL Report for material, environment, and aging effect. In addition, 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 in the GALL Report a different component with the same material, environment, aging effect, and AMP as the component under review. The staff audited these items to verify consistency with the GALL Report. The staff also determined if the AMR item of the different component was applicable to the component under review and if the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR item, although different from the component identified in the GALL Report, 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 audited these items to verify consistency with the GALL Report. The staff confirmed whether the AMR item of the different component was applicable to the component under review and whether the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined if the applicant's AMP was consistent with the GALL Report AMP and if the AMR was valid for the site-specific conditions.

Note E indicates that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff audited these items to verify consistency with the GALL Report. The staff also determined if the credited AMP would manage the aging effect consistently with the GALL Report AMP and if the AMR was valid for the site-specific conditions.

3.0.2.3 Updated Final Safety Analysis Report 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.

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 they are bounded by the conditions for which the GALL Report was evaluated.

Unless otherwise stated, the staff compared elements one through six of the applicant's program to the corresponding elements of GALL Report and found the elements are bounded. For program elements inconsistent with the corresponding element of GALL Report, the staff determined the need for additional clarification, which resulted in the issuance of a request for additional information (RAI).

3.0.3 Aging Management Programs

SER Table 3.0-1 presents the AMPs credited by the applicant and described in LRA Appendix B. The table also indicates the systems or structures, which credit the AMPs 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 3.0-1. Aging Management Programs

AMP (LRA section)	LRA section(s)	New or existing AMP	GALL Report comparison	GALL Report AMPs	Staff's SER section
ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program	A.2.1.1 B.2.1.1	Existing	Consistent	XI.M1, "ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD"	3.0.3.1.1
Water Chemistry Program	A.2.1.2 B.2.1.2	Existing	Consistent	XI.M2, "Water Chemistry Program"	3.0.3.1.2

AMP (LRA section)	LRA section(s)	New or existing AMP	GALL Report comparison	GALL Report AMPs	Staff's SER section
Reactor Head Closure Studs Program	A.2.1.3 B.2.1.3	Existing	Consistent with exception	XI.M3, "Reactor Head Closure Studs Program"	3.0.3.2.1
Boric Acid Corrosion Program	A.2.1.4 B.2.1.4	Existing	Consistent	XI.M10, "Boric Acid Corrosion"	3.0.3.1.3
Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program	A.2.1.5 B.2.1.5	Existing	Consistent	XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program"	3.0.3.1.4
Fuse Holders Program	A.2.1.36 B.2.1.36	New	Consistent	XI.E5, "Fuse Holders Program"	3.0.3.1.5
Flow-Accelerated Corrosion Program	A.2.1.8 B.2.1.8	Existing	Consistent	XI.M17, "Flow-Accelerated Corrosion"	3.0.3.1.6
Bolting Integrity Program	A.2.1.9 B.2.1.9	Existing	Consistent	XI.M18, "Bolting Integrity"	3.0.3.1.7
Steam Generator Tube Integrity Program	A.2.1.10 B.2.1.10	Existing	Consistent with exception	XI.M19, "Steam Generator Tube Integrity"	3.0.3.2.2
Open-Cycle Cooling Water System Program	A.2.1.11 B.2.1.11	Existing	Consistent with exception	XI.M20, "Open-Cycle Cooling Water System Program"	3.0.3.2.3
Closed-Cycle Cooling Water System Program	A.2.1.12 B.2.1.12	Existing	Consistent with exceptions and enhancements	XI.M21, "Closed-Cycle Cooling Water System Program"	3.0.3.2.4
Inspection of Overhead Heavy Load and Light Load Handling Systems Program	A.2.1.13 B.2.1.13	Existing	Consistent with enhancements	XI.M23, "Inspection of Overhead Heavy Load and Light Load Handling Systems Program"	3.0.3.2.5
Compressed Air Monitoring Program	A.2.1.14 B.2.1.14	Existing	Consistent with enhancement	XI.M24, "Compressed Air Monitoring"	3.0.3.2.6
Fire Protection Program	A.2.1.15 B.2.1.15	Existing	Consistent with enhancements	XI.M26, "Fire Protection Program"	3.0.3.2.7
Fire Water System Program	A.2.1.16 B.2.1.16	Existing	Consistent with enhancements	XI.M27, "Fire Water System Program"	3.0.3.2.8
Aboveground Steel Tanks Program	A.2.1.17 B.2.1.17	Existing	Consistent with enhancements	XI.M29, "Aboveground Steel Tanks"	3.0.3.2.9
Fuel Oil Chemistry Program	A.2.1.18 B.2.1.18	Existing	Consistent with exceptions and enhancements	XI.M30, "Fuel Oil Chemistry Program"	3.0.3.2.10
RV Surveillance Program	A.2.1.19 B.2.1.19	Existing	Consistent with enhancements	XI.M31, "Reactor Vessel Surveillance Program"	3.0.3.2.11

AMP (LRA section)	LRA section(s)	New or existing AMP	GALL Report comparison	GALL Report AMPs	Staff's SER section
One-Time Inspection Program	A.2.1.20 B.2.1.20	New	Consistent	XI.M32, "One-Time Inspection"	3.0.3.1.8
Selective Leaching of Materials Program	A.2.1.21 B.2.1.21	New	Consistent with exception	XI.M33, "Selective Leaching of Materials Program"	3.0.3.2.12
Buried Piping and Tanks Inspection Program	A.2.1.22 B.2.1.22	New	Plant-specific	None	3.0.3.3.1
One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program	A.2.1.23 B.2.1.23	New	Consistent with exception	XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program"	3.0.3.2.13
External Surfaces Monitoring Program	A.2.1.24 B.2.1.24	Existing	Consistent with exceptions and enhancement	XI.M36, "External Surfaces Monitoring Program"	3.0.3.2.14
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	A.2.1.25 B.2.1.25	New	Consistent with exceptions	XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program"	3.0.3.2.15
Lubricating Oil Analysis Program	A.2.1.26 B.2.1.26	Existing	Consistent with exception and enhancements	XI.M39, "Lubricating Oil Analysis Program"	3.0.3.2.16
ASME Code Section XI, Subsection IWE Program	A.2.1.27 B.2.1.27	Existing	Consistent	XI.S1, "ASME Section XI, Subsection IWE Program"	3.0.3.1.9
ASME Code Section XI, Subsection IWL Program	A.2.1.28 B.2.1.28	Existing	Consistent with enhancements	XI.S2, "ASME Section XI, Subsection IWL Program"	3.0.3.2.17
ASME Code Section XI, Subsection IWF Program	A.2.1.29 B.2.1.29	Existing	Consistent	XI.S3, "ASME Section XI, Subsection IWF Program"	3.0.3.1.10
10 CFR Part 50, Appendix J Program	A.2.1.30 B.2.1.30	Existing	Consistent	XI.S4, "10 CFR Part 50, Appendix J Program"	3.0.3.1.11
Structures Monitoring Program	A.2.1.31 B.2.1.31	Existing	Consistent with enhancements	XI.S5, "Masonry Wall Program" XI.S6," Structures Monitoring Program" XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants"	3.0.3.2.18

AMP (LRA section)	LRA section(s)	New or existing AMP	GALL Report comparison	GALL Report AMPs	Staff's SER section
Electrical Cables and Connections Not Subject to 10 CFR 50.49 environmental qualification (EQ) Requirements Program	A.2.1.32 B.2.1.32	New	Consistent	XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program"	3.0.3.1.12
Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program	A.2.1.33 B.2.1.33	New	Consistent	XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program"	3.0.3.1.13
Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program	A.2.1.34 B.2.1.34	New	Consistent with enhancement	XI.E3, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program"	3.0.3.2.19
Metal Enclosed Bus (MEB) Program	A.2.1.35 B.2.1.35	New	Consistent	XI.E4, "Metal Enclosed Bus Program"	3.0.3.1.14
Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Program	A.2.1.37 B.2.1.37	New	Consistent	XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program"	3.0.3.1.15
Protective Coating Monitoring and Maintenance Program	A.2.1.38 B.2.1.38	Existing	Consistent with enhancements	XI.S8, "Protective Coating Monitoring and Maintenance Program"	3.0.3.2.20
345 kV sulfur hexafluoride (SF_6) Bus Program	A.2.1.1 B.2.2.1	New	Plant-specific	None	3.0.3.3.2
Boral Monitoring Program	A.2.2.2 B.2.2.2	Existing	Plant-specific	None	3.0.3.3.3
Nickel-Alloy Nozzles and Penetrations Program	A.2.2.3 B.2.2.3	Existing	Plant-specific	None	3.0.3.3.4
Metal Fatigue of Reactor Coolant Pressure Boundary (RCPB) Program	A.2.3.1 B.2.3.1	Existing	Consistent with enhancements	X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary"	3.0.3.2.21
Pressure-Water Reactor (PWR) Vessel Internals Program	A.2.1.7 B.2.1.7	New	Plant-specific	None	3.0.3.3.5

AMP (LRA section)	LRA section(s)	New or existing AMP	GALL Report comparison	GALL Report AMPs	Staff's SER section
EQ of Electric Equipment Program	A.2.3.2 B.2.3.2	Existing	Consistent	X.E1, "Environmental Qualification (EQ) of Electric Components"	3.0.3.1.16

3.0.3.1 Aging Management Programs Consistent with the Generic Aging Lessons Learned Report

In LRA Appendix B, the applicant identified the following AMPs as consistent with the GALL Report:

- American Society of Mechanical Engineers (ASME) Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- Water Chemistry Program
- Boric Acid Corrosion Program
- Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program
- Fuse Holders Program
- Flow-Accelerated Corrosion Program
- Bolting Integrity Program
- One-Time Inspection Program
- ASME Code Section XI, Subsection IWE Program
- ASME Code Section XI, Subsection IWF Program
- 10 CFR Part 50, Appendix J Program
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements Program
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program
- Metal Enclosed Bus (MEB) Program
- Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Program
- EQ of Electrical Components Program

3.0.3.1.1 ASME Code Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.1 describes the existing ASME Code Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program, as consistent with GALL Report AMP XI.M1, "ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD." The applicant stated that this program manages the aging effects of cracking due to cyclic, thermal, or mechanical loading; stress corrosion; loss of fracture toughness due to thermal embrittlement; and loss of material due to pitting, crevice

corrosion, or wear. The applicant also stated that this program manages aging degradation in ASME Code Classes 1, 2, and 3 piping and components within the scope of license renewal. The applicant further stated that the program includes periodic visual inspection, surface or volumetric examination or both for components identified in ASME Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” or commitments that require an augmentation of inservice inspection (ISI). The applicant also stated that the program will provide the requirements for ISI, repair, and replacement of all ASME Code Classes 1, 2, and 3 components. The applicant further stated that the program consists of condition monitoring activities that will detect degradation of components prior to the 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 if 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 Report 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 Report AMP XI.M1, with the exception of the “detection of aging effects” program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of a request for additional information (RAI).

GALL Report AMP XI.M1 recommends that Class 1 component inspections include ASME Code Section XI examination Categories B–F and B–J. During the audit, the staff found that the applicant is currently including applicable portions of the Categories B–F and B–J in its Risk Informed Inservice Inspection Program. The staff noted that the approval of the risk-informed methodology cannot be assumed for the subsequent 10-year ISI intervals because the staff’s approval of an alternative program or relief request typically does not extend beyond the current 10-year interval for which the alternative was proposed. An applicant must submit relief requests in accordance with 10 CFR 50.55a(a)(3) for use in subsequent 10-year ISI intervals during the period of extended operation. By letter dated December 14, 2010, the staff issued RAI B.2.1.1-1 requesting that the applicant clarify how the inspection of Categories B-F and B-J will be implemented during the period of extended operation.

In its response dated January 13, 2010, the applicant stated that this program has been revised to state that Risk Informed ISI is implemented as an alternative to Categories B-F and B-J, as approved by the NRC, for each individual ISI interval. The applicant also stated that if the Risk Informed ISI Program is not approved during the period of extended operation, it will follow the applicable requirements of ASME Code Section XI, Subsection IWB.

Based on its review, the staff finds the applicant’s response to RAI B.2.1.1-1 acceptable because the applicant modified its ASME Code Section XI ISI, Subsection IWB, IWC, and IWD Program. This modification indicated that, if the Risk Informed ISI is not approved for any of the inspection intervals during the period of extended operation, the applicant will instead use the requirements in the ASME Code Section XI, consistent with the recommendations of GALL Report AMP XI.M1. The staff’s concern described in RAI B.2.1.1-1 is resolved.

Based on its audit and review of the applicant’s response to RAI B.2.1.1-1, the staff finds that elements one through six of the applicant’s ASME Code Section XI ISI, Subsection IWB, IWC, and IWD Program are consistent with the corresponding program elements of GALL Report AMP XI.M1 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.1 summarizes operating experience related to the ASME Code Section XI ISI, Subsection IWB, IWC, and IWD Program. In March 2008, the applicant stated that, during a routine visual inspection, excessive dry boric acid accumulation on a containment building spray system valve gland leak-off plug was identified. The applicant stated that the gland leak-off plug was tightened, and the leakage was stopped. The applicant further stated that, in September 2006, while performing a VT-2 visual examination, the inspector identified a packing leak from a main steam valve with the emergency feedwater steam supply header pressurized to the main steam header pressure. The applicant stated that it adjusted the packing to stop the leak. The applicant stated that these examples demonstrate that the VT-2 inspections have been effective in identifying degraded conditions.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 also conducted an independent search of the plant operating experience information to determine if the applicant 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 the 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 corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.1 provides the UFSAR supplement for the ASME Code Section XI ISI, Subsection IWB, IWC, and IWD 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 3.1-2. The staff determined 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 Code Section XI ISI, Subsection IWB, IWC, and IWD Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant 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 Water Chemistry Program

Summary of Technical Information in the Application. LRA Section B.2.1.2 describes the existing Water Chemistry Program as consistent with GALL Report AMP XI.M2, "Water Chemistry." The applicant stated that its Water Chemistry Program manages aging effects of cracking, loss of material, and reduction of heat transfer. The applicant further stated that the primary scope of the program is the RCS and related auxiliary systems. The applicant also stated that the program is used to control water chemistry for impurities. The applicant stated that the chemistry parameters include chlorides, fluorides, dissolved oxygen, and sulfate concentrations. The applicant stated that it bases its monitoring and control on industry guidelines such as Electrical Power Research Institute's (EPRI) "Pressurized Water Reactor Primary Water Chemistry Guidelines—Revision 6," for primary water chemistry and "Pressurized Water Reactor Secondary Water Chemistry Guidelines—Revision 7," for secondary water chemistry.

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 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 Report AMP XI.M2. 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 Report AMP XI.M2, with the exception of the "monitoring and trending" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

GALL Report AMP XI.M2 states that whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is used to verify the effectiveness of these actions. However, during its audit, the staff reviewed the applicant's chemistry guidelines and could not identify any statements that indicated under abnormal chemistry conditions the sampling frequency should be increased. By letter dated November 18, 2010, the staff issued RAI B.2.1.2-1 requesting that the applicant describe how the Water Chemistry Program will verify the effectiveness of corrective actions when an abnormal chemistry conditions occurs.

In its response dated February 18, 2011, the applicant committed (Commitment No. 62) to revise the chemistry program documents to include the statement that sampling frequencies are increased, as appropriate, when chemistry action levels are exceeded. The staff finds the applicant's response acceptable because it committed to include increased sampling frequencies when chemistry action levels are exceeded, which is consistent with GALL Report AMP XI.M2. The staff's concern described in RAI B.2.1.2-1 is resolved.

Based on its audit and review of the applicant's response to RAI B.2.1.2-1, the staff finds that elements one through six of the applicant's Water Chemistry Program are consistent with the corresponding program elements of GALL Report AMP XI.M2 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.2 summarizes operating experience related to the Water Chemistry Program. The applicant stated that in December 2001, the condensate storage tank (CST) oxygen levels increased above 75 parts per billion (ppb). The applicant stated that it took corrective actions by monitoring oxygen concentrations at various points in the condensate and demineralized water system. The applicant stated that the oxygen ingress was caused by the air in-leakage from the condensate storage pump. The applicant stated it repaired the pump, and the CST returned to within the Water Chemistry Program specifications. The applicant also indicated that, in the fall of 2003, the steam generator sludge analysis results indicated that low or less than detectable concentration of contaminants and sulfur were detected by bulk deposit analysis. The applicant stated that this was an example of the effectiveness of the secondary chemistry control.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 if the applicant adequately incorporated and evaluated operating experience related to this program. During its review, the staff identified 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. The staff determined the need for additional clarification, which resulted in the issuance of an RAI.

In LRA Section B.2.1.2, the applicant stated that it addressed operating experience related to water chemistry. However, the staff found that the applicant had a recurring condition with the CST where the specific conductivity is high and out of specification. By letter dated November 18, 2010, the staff issued RAI B.2.1.2-2 requesting that the applicant provide additional information to explain if the CST conductivity excursions were evaluated for similar root causes. If the root cause is the same for the three instances referenced previously, the applicant was asked to provide additional information on what steps have been taken to reduce the occurrence of any future CST conductivity excursions.

In its response dated December 17, 2010, the applicant stated that the high specific conductivity in the CST could have been due to either recirculation flows from the startup feed pump and emergency feedwater pumps or air ingress past the CST floating lid seal. The applicant stated that when the high specific conductivity started, it immediately sampled the CST to determine if any leakage from the auxiliary steam side into the CST had occurred; however, no leakage was found. The applicant stated that the tank was then fed and bled to reduce the high specific conductivity to within acceptable limits. The applicant further stated that during the April 2008 refueling outage, it replaced the faulty floating lid seal, and since this time, the specific conductivity has remained below the 0.1 siemens (S)/cm limit. An additional step for conductivity control has been the continued monitoring and replacement of the CST float seal when necessary and the supply of condenser hotwell makeup from the demineralized water storage tank instead of the CST. Based on its review, the staff finds the applicant's response to RAI B.2.1.2-2 acceptable because the applicant indicated how this program brought the water chemistry excursions back within limits; determined that the likely root cause for the events was due to either recirculation flows from the startup feed pump and emergency feedwater pumps or air ingress past the CST floating lid seal that the applicant replaced; and used monitoring, replacement, and alternate condenser water sources to minimize the possibility of conductivity excursions. The staff's concern described in RAI B.2.1.2-2 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B.2.1.2-2, the staff finds that operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; 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 noted 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, 3.4-2, and 3.5-2. The staff determined 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 Water Chemistry Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant 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 Boric Acid Corrosion Program

Summary of Technical Information in the Application. LRA Section B.2.1.4 describes the existing Boric Acid Corrosion Program as consistent with GALL Report AMP XI.M10, "Boric Acid Corrosion." The applicant stated that its Boric Acid Corrosion Program manages loss of material in mechanical, electrical, and structural components due to leakage from systems containing borated water. The applicant further stated that the program implements the recommendations of NRC Generic Letter (GL) 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The applicant also stated that the program includes visual inspections and early discovery of borated water leaks such that mechanical, electrical, and structural components that may be contacted by leaking borated water will not be adversely affected or their intended functions impaired. The applicant also stated that the program includes both focused inspections and observations by plant personnel during normal operational activities and during refueling shutdowns to identify boric acid accumulation or leakage.

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 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 Report AMP XI.M10. As discussed in the audit report, the staff confirmed that these elements are consistent with the corresponding elements of GALL Report AMP XI.M10. Based on its audit, the staff finds that elements one through six of the applicant's Boric Acid Corrosion Program are consistent with the corresponding program elements of GALL Report AMP XI.M10 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.4 summarizes operating experience related to the Boric Acid Corrosion Program. The applicant's operating experience provided details on engineering analyses and corrective actions taken in response to detected leakage of boric acid. In one recorded instance of operating experience, the applicant described the detection of boric acid residue on a chemical and volume control system valve during a plant walkdown. The observation led to actions to replace the affected valve packing. In another instance, the applicant described the detection of boric acid residue on a RHR system valve. The observation led to actions to replace the affected valve gasket.

The applicant provided an account of a self-assessment of its Boric Acid Corrosion Program conducted in 2008. The self-assessment compared the Seabrook Boric Acid Corrosion Program to the current industry guidance document, [Westinghouse Commercial Atomic Power] WCAP-15988-NP, Revision 1, "Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors," which identifies potential enhancements to the Boric Acid Corrosion Programs described in the utility responses to GL 88-05. The applicant stated that, based on the results of the self-assessment, the program was operationally sound and deemed to be in a mode of continuous improvement. The applicant further described the self-assessment as a source of identified areas where the program could benefit by being more prescriptive in addressing some of the objectives in the Westinghouse Commercial Atomic

Power citation. Condition reports were generated during the course of the self-assessment. None of these condition reports identified programmatic failures, and all were directed towards future Boric Acid Program enhancements.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 plant operating experience information to determine if the applicant 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 effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.4 provides the UFSAR supplement for the Boric Acid Corrosion 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 Tables 3.1-2, 3.2-2, 3.3-2, 3.4-2, 3.5-2, and 3.6-2. The staff determined 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 Boric Acid Corrosion Program, the staff finds that all program elements are consistent with GALL Report AMP XI.M10. The staff concludes that the applicant 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 Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program

Summary of Technical Information in the Application. LRA Section B.2.1.5 describes the existing Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program (hereafter Nickel-Alloy Head Penetration Program) as consistent with GALL Report AMP XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors." The applicant stated that the program manages the aging effect of cracking due to primary water stress corrosion cracking (PWSCC) in the reactor coolant environment. The applicant also stated that the program includes all nickel-alloy penetration nozzles welded to the upper reactor vessel head. The applicant further stated that cracking was mitigated through the control of water chemistry. The applicant finally stated that inspections are performed in accordance with ASME Code Case N-729-1, "Alternative Examination Requirements for PWR Reactor Vessel Upper Heads With Nozzles Having Pressure-Retaining Partial-Penetration Welds, Section XI, Division 1, Supp 4," as modified in 10 CFR 50.55a(g)(6)(ii)(D), and this code case and regulation meet the AMP criteria of being "established to supersede the requirements of Order EA-03-009."

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 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 Report AMP XI.M11A. The staff confirmed that these elements are consistent with the corresponding elements of GALL Report AMP XI.M11A. Based on its review, the staff finds that elements one through six of the applicant's Nickel-Alloy Head Penetration Program are consistent with the corresponding program elements of GALL Report AMP XI.M11A and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.5 summarizes operating experience related to the Nickel-Alloy Head Penetration Program. In this section, the applicant states that it has conducted several inspections of the upper vessel head penetration nozzles and that it has not detected any indication of PWSCC. As evidence of the effectiveness of its AMP, the applicant provides descriptions of inspection findings for RFOs 8, 9, 10, and 11 (spring 2002, fall 2003, spring 2005, and fall 2006, respectively). In RFO 8, the applicant performed a robotic bare metal exam of the top head. The applicant stated that no evidence of penetration leakage was observed. In RFO 9, boric acid was observed on the upper reactor vessel head flange. This acid was traced to two leaking canopy seal welds. The applicant states that no boric acid corrosion was observed. The leakage was halted through the application of a canopy seal clamp assembly. The applicant attributed the leakage to transgranular cracking due to the presence of halogens, probably chlorides. Followup inspections conducted during RFO 10 and RFO 11 did not identify additional canopy seal weld leaks. In RFO 11, inspections were conducted under the first revised NRC Order 03-009. These inspections included a robotic bare metal examination from the top of the head and a robotic ultrasonic and surface examination of the J-groove welds and penetration tubes from the bottom of the head. The applicant stated that no unacceptable indications were discovered.

The staff reviewed operating experience information—which is contained in the application, in the GALL Report, and which has occurred since the publication of the GALL Report—to determine if all the applicable aging effects and industry and plant-specific operating experience were considered by the applicant and whether the proposed AMP is sufficient to address this operating experience. 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 GALL Report, and recent industry operating experience, 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 preventive actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.5 provides the UFSAR supplement for the Nickel-Alloy Head Penetration 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 3.1-2. The staff determined 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 Nickel-Alloy Head Penetration Program, the staff finds that program elements 1–6 and 10 are consistent with the GALL Report. The staff concludes that the applicant 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 Fuse Holders Program

Summary of Technical Information in the Application. LRA Section B.2.1.36 describes the new Fuse Holders Program as consistent with GALL Report AMP XI.E5, "Fuse Holders." The applicant stated that the Fuse Holders Program is a new program that will manage the aging effects of thermal fatigue in the form of high resistance due to corrosion or oxidation of in-scope metallic clamps of fuse holders. The applicant also stated that the program will perform tests on the in-scope fuse holders (metallic clamps). The applicant further stated that the test will be a proven test such as thermography or contact resistance, which detects thermal fatigue in the form of high resistance caused by corrosion or oxidation. The first test will be completed prior to entering the period of extended operation and at least once every 10 years thereafter.

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 Report AMP XI.E5. 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 Report AMP XI.E5, with the exception of the "parameters monitored or inspected" program element. For this element, the staff determined that additional clarification was required.

GALL Report AMP XI.E5, under the "parameters monitored or inspected" element, states that the monitoring includes thermal fatigue in the form of high resistance caused by ohmic heating, thermal cycling or electrical transients, mechanical fatigue caused by frequent removal or replacement of the fuse or vibration, chemical contamination, corrosion, and oxidation. In the Seabrook AMP basis document LRAP-E5 under the same program element, the applicant states that the Seabrook program only includes monitoring for the presence of corrosion and oxidation. The applicant concluded that the aging effects and mechanisms due to thermal fatigue—in the form of high resistance caused by ohmic heating, thermal cycling or electrical transients, mechanical fatigue caused by frequent removal or replacement of the fuse or vibration—identified by GALL are not applicable to the fuse holders at Seabrook. However, the applicant does not provide any justification to substantiate its conclusion. During the LRA onsite audit in the week of October 18, 2010, the staff discussed the applicant's lack of analysis to exclude certain aging effects for fuse holder metallic clamps in the scope of license renewal. In a letter dated November 15, 2010, the applicant revised the Fuse Holders Program description to clarify the exclusion of certain aging mechanisms from the AMP. The staff finds the exclusion of certain aging mechanisms acceptable, as documented in SER Section 3.6.2.3.1.

Based on its audit and review of the applicant's response by letter dated November 15, 2010, the staff finds that elements one through six of the applicant's Fuse Holders Program are consistent with the corresponding program elements of GALL Report AMP XI.E5 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.36 summarizes operating experience related to the Fuse Holders Program. The applicant's Fuse Holders Program operating experience evaluation states that Seabrook routinely performs infrared thermography tests on numerous pieces of equipment, including electrical connections, as part of the Preventive Maintenance Program. In 2008, during a routine infrared thermography test, a fuse holder was found to be 50°F [degrees Fahrenheit] hotter than similar fuses in the cabinet. The problem was diagnosed as a defective fuse holder. The documentation identified this anomaly as defective equipment and not age-related. The applicant also stated that Seabrook has performed thermography or resistance tests on fuses located in the in-scope fuse panels. All recent tests were reviewed and found to be satisfactory. The applicant further stated that, in 2009, members of the Seabrook license renewal team performed a walkdown of the in-scope Train "B" fuse cabinets. The walkdown assessed the current condition of the in-scope fuse panels. The applicant stated that the walkdown results concluded that fuse blocks showed no signs of excessive heating, discoloration, corrosion, degradation, or looseness. However, a condition report was written to document the presence of a residue on the fuse cabinet mounting bolts. The evaluation of the anomaly concluded that residue on the bolts had no effect on the fuse holders.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 plant operating experience information to determine if the applicant adequately incorporated and evaluated operating experience related to this program. Further, the staff performed a search of regulatory operating experience for the past 10-year period through March 2010. Databases were searched using various key word searches and then reviewed by the technical auditor staff.

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 has resulted in the applicant taking corrective action. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.36 provides the UFSAR supplement for the Fuse Holders 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 3.6-2. The staff also noted that the applicant committed (Commitment No. 38) to implement the new Fuse Holders Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determined 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 Fuse Holders Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant 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 Flow-Accelerated Corrosion Program

Summary of Technical Information in the Application. LRA Section B.2.1.8 describes the existing Flow-Accelerated Corrosion Program as consistent with GALL Report AMP XI.M17, "Flow-Accelerated Corrosion." The applicant stated that this program manages loss of material due to wall thinning on the internal surfaces of carbon or low alloy steel components containing high-energy fluids. The applicant also stated that the program is based on the guidelines of EPRI NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program," which includes determining susceptible lines, performing baseline and followup inspections to confirm predictions, and repairing or replacing components if needed. The applicant further stated that the program monitors the effects of flow-accelerated corrosion by measuring wall thickness of the components, and the inspection schedule is developed based on model prediction, inspection results, and operating experience.

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 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 Report AMP XI.M17. 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 Report AMP XI.M17, with the exception of the "parameters monitored or inspected" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

GALL Report AMP XI.M17 recommends that the program monitors the aging effects of flow-accelerated corrosion on the intended function of piping and components by measuring wall thickness. LRA Section B.2.1.8 states that valves, orifices, equipment nozzles, and other like components, which cannot be inspected completely with ultrasonic testing (UT) techniques due to their shape and thickness, are evaluated based on the wear of piping located immediately downstream. By letter dated December 14, 2010, the staff issued RAI B.2.1.8-1 requesting that the applicant provide additional information regarding inspection of the valves, orifices, equipment nozzles, and other like components that cannot be inspected completely with ultrasonic techniques due to their shape and thickness if significant wear is detected in piping located immediately downstream. The staff also asked the applicant to explain how the followup inspections will be implemented in the Flow-Accelerated Corrosion Program.

In its response dated January 13, 2011, the applicant stated that its Flow-Accelerated Corrosion Program is revised to state that if significant wear is detected in piping immediately downstream of a valve, orifice, equipment nozzle or other like component, the component should also be examined. The applicant also stated that these components will be examined by ultrasonic, radiographic, or visual techniques typically used to inspect valves, orifices, and equipment nozzles. The applicant further stated that the followup inspections will be implemented in the Flow-Accelerated Corrosion Program, which is consistent with the guidelines delineated in NSAC-202L-R2.

The staff finds the applicant's response acceptable because the applicant's Flow-Accelerated Corrosion Program will implement the guidance of NSAC-202L-R2 to include inspections of valves, orifices, equipment nozzles, and other like components using ultrasonic, radiographic, or visual techniques if significant wear is detected in the downstream pipe, which makes the applicant's program consistent with GALL Report AMP XI.M17. The staff's concern described in RAI B.2.1.8-1 is resolved.

Based on its audit and review of the applicant's response to RAI B.2.1.8-1, the staff finds that elements one through six of the applicant's Flow-Accelerated Corrosion Program are consistent with the corresponding program elements of GALL Report AMP XI.M17 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.8 summarizes operating experience related to the Flow-Accelerated Corrosion Program. The applicant stated that following the initial implementation of CHECWORKS in 1991, a significant portion of the high-pressure extraction steam piping was found to be degraded during the first flow-accelerated corrosion inspections. As a result, the applicant stated it replaced the piping with a chrome-moly material that is more resistant to flow-accelerated corrosion, and no degradation has been noted in the piping after replacement. The applicant also stated that during RFO 8 in 2002, it identified one feedwater heater with wall thinning in the area below the extraction steam inlet nozzle and took appropriate corrective actions to repair the heater using a weld overlay. The applicant further stated that the component is being monitored during each RFO, and no additional wall thinning has been observed since the repair.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 if the applicant 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 effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.8 provides the UFSAR supplement for the Flow-Accelerated Corrosion 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 Tables 3.1-2, 3.2-2, and 3.4-2. The staff determined 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 Flow-Accelerated Corrosion Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant 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 Bolting Integrity Program

Summary of Technical Information in the Application. LRA Section B.2.1.9 describes the existing Bolting Integrity Program as consistent with GALL Report AMP XI.M18, "Bolting Integrity." The applicant stated that the program covers bolting within the scope of license renewal, including safety-related bolting, bolting for nuclear steam supply system (NSSS) component supports, bolting for other pressure-retaining components (including nonsafety-related bolting), and structural bolting. The applicant also stated that the program manages the aging effects of cracking due to stress corrosion cracking, loss of material due to general, crevice, pitting, and galvanic corrosion, microbiologically-influenced corrosion, fouling and wear, and loss of preload due to thermal effects, gasket creep, and self-loosening associated with bolting. The applicant further stated that the program manages the aging effects associated with bolting through material selection and testing, bolting assembly and pre-load control, operation, maintenance, and the performance of periodic inspections. The applicant stated that the program relies on the performance of periodic inspections and credits other AMPs for the inspection of bolting such as the ASME Code Section XI, ISI, Subsections IWB, IWC, and IWD Program (B.2.1.1). The applicant further stated that the program follows the guidelines and recommendations delineated in the following documents:

- NUREG-1339, "Resolution of Generic Safety Issue 29; Bolting Degradation or Failure of Bolting in Nuclear Power Plants"
- EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants" (with the exceptions noted in NUREG-1339)
- EPRI TR-104213, "Bolted Joint Maintenance and Application Guide," for comprehensive bolting maintenance

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 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 Report 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 element of GALL Report AMP XI.M18, with the exception of the "parameters monitored or inspected" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

GALL Report AMP XI.M18 recommends that safety-related and nonsafety-related bolting be visually inspected for leakage under the "parameters monitored or inspected" program element. However, during its audit, the staff found that there are in-scope components in the applicant's fire protection system, service water system, and spent fuel pool cooling system that are in moist or submerged environments for which visual inspection to detect leakage is not feasible due to the environmental conditions. By letter dated November 18, 2010, the staff issued RAI B.2.1.9-1 requesting that the applicant provide details on how the in-scope components in wet environments will be inspected for leakage.

In its response dated December 17, 2010, the applicant stated that the Bolting Integrity Program will be amended to credit the Open-Cycle Cooling Water System Program to manage the aging effects of loss of material and loss of preload in submerged in-scope bolting, specifically, the service water pump column bolting. The applicant also stated that through inspections implemented by the Open-Cycle Cooling Water System Program, the water pump column bolted connections, which are submerged in raw water, will be visually inspected when the pumps are removed for maintenance. The applicant further stated that a corrective action document has been generated to require inspection for loose or missing in-scope bolts. The applicant further stated that the stainless steel bolting in the spent fuel pool cooling system externally exposed to borated water was incorrectly shown as being in-scope in LRA Table 3.3.2-39. The item was subsequently removed due to the fact that those bolts were reassessed to be out of the scope of license renewal since they are associated with an out of scope component and provide no pressure boundary function.

The applicant also stated that the Buried Piping and Tanks Inspection Program will be used to manage aging effects for bolting used in buried, underground, and inaccessible submerged piping. The applicant further stated that in instances where hydrostatic testing, flow testing, or fire protection jockey pump monitoring are used in lieu of visual inspections, these methods will also be credited to identify leakage caused by loss of preload at bolted connections. The applicant also stated that the Buried Piping and Tanks Inspection Program will be used in conjunction with the ISI Program and the External Surfaces Monitoring Program, which are cited in the LRA as credited for managing the aging effects of bolting.

The staff finds the applicant’s response acceptable because the applicant amended the LRA to manage wet or submerged bolting with AMPs that are appropriate for these specific environments. These AMPs can manage the loss of material through the implementation of periodic and opportunistic visual inspections and loss of preload through hydrostatic testing, flow testing, pump monitoring, visual inspections, and other inspections to detect leakage or loose and missing bolts. In addition, the staff finds the removal of the two items in LRA Table 3.3.2-39 acceptable and determined the bolts are out of the scope of license renewal since they are associated with an out of scope component and provide no pressure boundary function.. The staff’s concern described in RAI B.2.1.9-1 is resolved.

Based on its audit and review of the applicant’s response to RAI B.2.1.9-1, the staff finds that elements one through six of the applicant’s Bolting Integrity Program are consistent with the corresponding program elements of GALL Report AMP XI.M18 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.9 summarizes operating experience related to the Bolting Integrity Program. The applicant stated that rust was observed on the pipe supporting bolts for the RHR equipment vault, an engineering evaluation was conducted, the rusted condition was determined to not impact the function of the bolts, and the affected area was painted to prevent further degradation. The applicant also stated that galvanic corrosion was detected on the bolting associated with one of the containment air handling coolers, determined to be due to condensation on dissimilar metal interfaces, and the corrective action involved a materials substitution that provided adequate resistance to galvanic corrosion, which removed the susceptibility for further degradation.

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 industry operating experience for which it determined the need for additional clarification resulting in the issuance of an RAI, as discussed below.

The staff lacks sufficient information to conclude that the applicant's program is effective at managing aging of pressure-retaining bolting and component external surfaces which are surrounded by seal cap enclosures. The staff noted that in recent reviews of license renewal applications and operating experience, the applicant may have used, or currently uses, seal cap enclosures to contain water leakage, and the use of the enclosures may not be accounted for in the LRA. By letter dated May 29, 2012, the staff issued RAI B.2.1.9-2 requesting that for all pressure-retaining bolting and external surfaces that are surrounded by seal cap enclosures, the applicant describe a) the bolting and component material and the leaking water environment, b) new AMR items for the aging management of the bolting and external surfaces for loss of material, loss of preload, change in material properties, and cracking due to SCC in the submerged environment, c) technical justification for how the aging effects above are managed if direct inspection is not possible, and d) how future use of seal cap enclosures is controlled such that aging is managed. These issues are open item OI 3.0.3.1.7-1.

Based on its audit and review of the application, the staff finds, with the exception of OI 3.0.3.1.7-1, that operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that, pending resolution of OI 3.0.3.1.7-1, 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 Bolting Integrity 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 Tables 3.1-2, 3.2-2, 3.3-2, 3.4-2, and 3.5-2. The staff determined that, pending resolution of OI 3.0.3.1.7-1, 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 Bolting Integrity Program, the staff finds all program elements consistent with the GALL Report, with the exception of the "operating experience" program element, which is associated with OI 3.0.3.1.7-1. The staff concludes that, with the exception of OI 3.0.3.1.7-1, 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, pending resolution of OI 3.0.3.1.7-1, it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.8 One-Time Inspection Program

Summary of Technical Information in the Application. LRA Section B.2.1.20 describes the new One-Time Inspection Program as consistent with GALL Report AMP XI.M32, "One-Time Inspection." The applicant stated that the One-Time Inspection Program is a new program that addresses component, material, and environment combinations for which aging effects are either not occurring or are progressing so slowly as to have negligible effect on the intended function of the structure or components through the period of extended operation. The applicant also stated that the program will provide the following functions:

- determination of appropriate inspection sample size
- identification of inspection locations

- selection of examination techniques, including acceptance criteria
- evaluation of results to determine the need for additional inspections or other corrective actions

The applicant further stated that the inspection methods of the program may include visual (or remote visual), surface or volumetric examinations, or other established nondestructive examination techniques.

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 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 Report AMP XI.M32. As discussed in the audit report, the staff confirmed that these elements are consistent with the corresponding elements of GALL Report AMP XI.M32, with the exception of the "detection of aging effects" program element. In this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

GALL Report AMP XI.M32 states 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. However, during the staff's review of the applicant's One-Time Inspection Program, the staff noted that the applicant did not include specific information regarding how the sample set of components are to be selected or how the sample size will be determined. The staff also noted that large sample sizes (e.g., at least 20 percent) may be necessary in order to adequately confirm an aging effect does not occur because of the uncertainty in determining the most susceptible locations and the potential for aging to occur in other locations. By letter dated December 14, 2010, the staff issued RAI B.2.1.20-1 requesting that the applicant provide specific information regarding how the sample set of components will be selected and how the size of the sample of components will be determined.

In its response dated January 13, 2011, the applicant stated that the program will be modified to include the inspection of approximately 20 percent of the components of each in-scope material type, environment, and aging effect combination, but not to exceed 25 components. The staff noted that LRA Section B.2.1.20 states that the samples include locations where the most severe aging effects would be expected to occur. The samples will be based on aspects such as location, design, material of construction, service environment, and previous failure history, and they will include stagnant or low-flow areas. The staff finds the applicant's response acceptable because the applicant's sampling methodology ensures a representative sample of material and environment combinations is considered, ensures sample locations will focus on the most susceptible components, and includes an appropriate sample size. The staff's concern described in RAI B.2.1.20-1 is resolved.

Based on its audit and review of the applicant's response to RAI B.2.1.20-1, 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 Report AMP XI.M32 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.20 summarizes operating experience related to the One-Time Inspection Program. The applicant stated that there is no operating experience specifically applicable to the new one-time inspections. However, the applicant provided examples of operating experience that indicated the existing Condition Monitoring and Condition Reporting Programs are effective in identifying, evaluating, and correcting aging effects typical of the scope of this program. For example, the applicant described an instance in which corrosion was observed on the pump discharge head flange during the replacement of a service water cooling tower pump. In response to the observed corrosion, the discharge head was replaced with a more corrosion-resistant material.

In another instance of operating experience, the applicant described a case in which a large amount of rust and scale was found in piping connecting valves with air receivers. The applicant stated that the response involved removal of all loose corrosion products, and no evidence of pitting or wall thinning was found.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 if the applicant 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 effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.20 provides the UFSAR supplement for the One-Time Inspection 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 Tables 3.1-2, 3.2-2, 3.3-2, and 3.4-2.

The staff also noted that in LRA Supplement 2 to the LRA, Appendix A, the applicant committed (Commitment No. 22) to implement the new One-Time Inspection Program within 10 years prior to the period of extended operation. The staff determined 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 One-Time Inspection Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant 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 ASME Code Section XI, Subsection IWE Aging Management Program

Summary of Technical Information in the Application. LRA Section B.2.1.27 describes the existing ASME Code Section XI, IWE AMP as consistent with GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE." The LRA states that this program manages aging effects of the containment steel liner plate, electrical penetrations, mechanical penetrations (piping, ventilation, and spares), personnel lock, equipment hatch, recirculation sump, reactor pit, moisture barriers, seals, gaskets, pressure-retaining bolting, and supports. Inspection of the containment liner plate and the associated components are performed in accordance ASME Code Section XI, Subsection IWE. The applicant also stated that the acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found are in accordance with the IWE requirements. According to the LRA, the applicant followed the requirements of the 1995 Edition, including the 1996 Addenda, of ASME Code Section XI, Sub-Section IWE for the first 10-year inspection interval effective from August 19, 2000–August 18, 2010, and in accordance with 10 CFR 50.55a. The applicant also stated that the next and subsequent 120-month inspection interval will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a, 12 months before the start of the inspection interval.

Summary of Staff Evaluation. The staff reviewed the various elements of the containment liner plate aging management program and found them consistent with the corresponding elements of GALL Report AMP XI.S1; however, the staff noted the applicant's previous failure to maintain the annular space between the containment and containment enclosure buildings in a dewatered state. Based on this operating experience, the applicant in Commitment 52, committed to maintain the annular space in a dewatered state. The staff is concerned that the applicant has not, until now, implemented procedures and inspection requirements to keep this area dewatered in the future. Accumulation of water in the annular space can potentially degrade the containment liner plate. The staff's concern is tracked as Open Item OI 3.0.3.1.9-1.

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 if 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 Report AMP XI.S1. As discussed in the audit report, the staff confirmed that these elements are consistent with the corresponding elements of GALL Report AMP XI.S1. Based on its audit, the staff finds that elements one through six of the applicant's ASME Code Section XI, Subsection IWE AMP are consistent with the corresponding program elements of GALL Report AMP XI.S1 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.27 summarizes operating experience related to the ASME Code Section XI, Subsection IWE AMP. The applicant stated it has reviewed the industry operating experience concerning containment liner plate degradation, including NRC Information Notices (INs) 86-99, "Degradation of Steel Containments," IN 88-82, "Torus Shells with Corrosion and Degraded Coatings in BWR Containments," IN 89-79, "Degraded Coatings and Corrosion of Steel Containment Vessels," and IN 97-10, "Liner Plate Corrosion in Concrete Containments," and considered their applicability to Seabrook. The applicant also stated that it has reviewed the containment liner issue from Beaver Valley, where inspections in 2009 revealed degradation from the inaccessible side of the steel liner. The applicant further stated that no potentially through-liner corrosion issues have been noted during the IWE examinations.

The applicant identified several condition reports in a search for “containment liner” documenting material found to be in contact with the containment liner (e.g., scaffolding, grating hose reels, and outage contractor storage boxes) during outage activities. These were promptly and appropriately dispositioned. In addition, the applicant stated, during the Seabrook nuclear oversight audit of key activities during RFO 7 (fall of 2000), one material was observed as a faulty moisture barrier at the minus 26 ft level, azimuth 250°. A condition report was initiated, and the barrier was repaired. The applicant also stated that, in November 2001, a condition report documented the opportunity to complete IWE examinations for containment recirculation sump area during the RFO window for containment liner inspection that had been inaccessible. The applicant stated that this condition report documented the understanding of the scope of this program and the ability to recognize respective windows of opportunity.

The staff reviewed operating experience information, in the application, and during the audit, to determine if 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 plant operating experience information to determine if the applicant adequately incorporated and evaluated operating experience related to this program. During its review, the staff identified operating experience that could indicate that the applicant’s program may not 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 RAIs.

During the AMP audit, the staff interviewed the applicant's staff and reviewed documentation about the groundwater seepage in different plant structures. The staff found that groundwater infiltrated into the annular space between the concrete enclosure building and concrete containment. The bottom 6 ft of the concrete containment wall was in contact with the groundwater for an extended period of time. In addition, cracks due to alkali-silica reaction (ASR) have been observed in different Seabrook plant concrete structures, including the concrete enclosure building. Therefore, the groundwater may have penetrated the concrete containment wall and come into contact with the containment liner plate. This can result in through-wall corrosion of the containment liner plate. Therefore, in a letter dated November 18, 2010, the staff issued RAI B.2.2.27-1. The staff requested that the applicant explain any plans to perform nondestructive examinations, such as UT, of the containment liner to demonstrate that the effects of prolonged exposure of the bottom portion of the concrete containment to groundwater have not introduced corrosion on the concrete side of the liner plate. Corrosion on the concrete side of the containment liner could affect its ability to perform its intended design function during the period of extended operation.

In its response, dated December 17, 2010, the applicant stated that Seabrook continues to monitor the annulus area including the exterior concrete surface of containment where groundwater had accumulated. The applicant also stated that the lack of oxygen and high pH alkali environment of the concrete are inhibitors to a corrosive environment that would be detrimental to the integrity of the liner; therefore, the potential for loss of material at the concrete to liner plate interface due to water accumulating in the annulus area is very low. However, based on NRC IN 2010-12, “Containment Liner Corrosion,” and other industry and site-specific operating experience, Seabrook will perform testing of the containment liner plate for loss of material. The applicant added an enhancement and commitment (Commitment No. 50) to its ASME Code Section XI, Subsection IWE AMP to perform testing of the containment liner plate for loss of material on the concrete side of the liner. The testing will be conducted in accordance with approved ASME Code Section XI, Subsection IWE methodology, and it will be completed prior to the period of extended operation. In addition, the applicant in accordance with Commitment 52 will implement measures to maintain the exterior surface of the containment structure from elevation -30 ft to +20 ft in a dewatered state.

The staff reviewed the applicant's response to RAI B.2.1.27-1 and noted that the applicant committed to perform testing of the containment liner plate for the loss of material on the side of the concrete; however, it is not clear how this testing will be performed. Therefore, in a letter dated March 17, 2011, the staff issued followup RAI B.2.1.27-1 requesting the applicant provide details regarding the testing to be performed to determine the loss of material on the concrete side of the liner plate. The staff asked that these details include a description of the nondestructive testing methods and locations where thickness measurements will be obtained and explain why the measurement locations will provide an adequate representation of liner plate locations that may be degraded.

In its response, dated April 14, 2011, the applicant stated that Seabrook will perform UT testing of the liner plate inside containment for loss of material on the concrete side of the liner. The testing will be subject to ASME Code Section XI, Subsection IWE acceptance criteria (the code currently in use at Seabrook is the 2004 ASME code) and will be completed by December 31, 2015. The applicant further stated under IWE 1241(a), Seabrook will designate the area of the containment liner that is within 10 in. of the moisture barrier at the containment basement floor for examination. This is the lowest accessible point on the liner and for potential degradation due to moisture; the lowest point is the most susceptible. Locations spaced at 10° increments (approximately every 12 ft) of accessible circumference, or locations showing visible signs of degradation, will be tested with one or more readings taken at each location. The examination will be repeated at intervals of no more than five RFOs. If any indications are found that show a loss of material exceeding 10 percent of nominal thickness (ASME Code acceptance criteria), an engineering evaluation of deficient indications will be performed and actions planned accordingly. The applicant revised the enhancement and Commitment No. 50 to perform UT testing in the vicinity of the moisture barrier for loss of material at a nominal 10° increment around the circumference of containment, and to complete it no later than December 31, 2015. The UT testing will be repeated at intervals of no more than five RFOs.

Based on its review, the staff finds the applicant's response acceptable because the applicant committed to monitor the containment liner plate condition and thickness prior to December 31, 2015, and subsequently at intervals of no more than five RFOs (7.5 years) before and during the period of extended operation. The UT testing will be performed at 10° increments (36 locations) around the circumference of containment. The augmented UT examination, in conjunction with visual examination in accordance with IWE, will provide reasonable assurance that any potential loss of material at the concrete-to-liner-plate interface due to water accumulating in the annulus area will not affect the structural integrity of the containment liner plate. In case loss of liner plate thickness is detected during the visual and UT examinations, the applicant will perform an engineering evaluation and will perform remedial actions in accordance with the Corrective Actions Program. The applicant's Commitment No. 50 also demonstrates that the applicant addressed operating experience identified after issuance of the GALL Report, including IN 2010-12, concerning through-wall corrosion of the liner plate at Beaver Valley Power Station. The staff's concerns in RAI B.2.1.27-1 and the associated followup RAI concerning liner plate corrosion and loss of material are resolved.

The staff also noted that, in response to RAI B.2.28-3, the applicant committed (Commitment No. 52) to implement measures to maintain the containment exterior surface between elevations -30 ft to +20 feet dewatered by December 31, 2012. During the December 31, 2010, inspection, NRC inspectors examined the subject area and found it in a dewatered state. Portable sump pumps are used to dewater the area. However, the staff is concerned that until now the applicant has not implemented any permanent measures for dewatering and revised procedures for routine inspection of this area. Accumulation of water in the annular space between the containment and containment enclosure buildings can potentially degrade the containment liner plate. The staff's concern is tracked as Open Item OI 3.0.3.1.9-1.

During the site audit, the staff reviewed documentation concerning the corrosion of the containment liner plate around the fuel transfer tube vault documented during the 2009 IWE inspection. The containment liner plate had indications of heavy corrosion. UT examination of the containment liner indicated that liner plate thickness varied between 0.484–0.411 in. (variation of 18 percent) within a small area. The applicant accepted this degradation of the liner plate based on engineering evaluation. The applicant justification for acceptance was that the measured thickness of the liner plate was still greater than the 0.375 in. nominal thickness of the liner plate. However, the staff did not find any requirement in the applicant's engineering evaluation that requires UT reexamination of the affected portion of the liner plate for three consecutive periods in accordance with IWE-2420. Therefore, in a letter dated November 18, 2010, the staff issued RAI B.2.2.27-2, requesting that the applicant provide the details of any actions planned for augmented examination of the containment liner plate around the fuel transfer tube where the corrosion was detected during the 2009 inspection.

In its response, dated December 17, 2010, the applicant stated that this condition requires augmented inspection in accordance with 1995 Edition with 1996 Addenda of the ASME Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWE-2420(b) and IWE-2420(c). The applicant further stated that the condition has been identified in the ISI Program database for reexamination during subsequent scheduled inspections.

The staff reviewed the applicant's response to RAI B.2.1.27-2 and noted that the ASME Code 1995 Edition with 1996 Addenda, Section XI, Subsection IWE-2420(b) and IWE-2420(c) state that reexamination of degraded areas is no longer required if these areas remain essentially unchanged for three consecutive inspection periods. However, it was not clear from the applicant's response if the containment liner plate around the fuel transfer tube is still exposed to the borated water leakage. Exposure to borated water can promote corrosion of the liner plate and adversely affect the ability of the liner to perform its intended function. Therefore, in a letter dated March 17, 2011, the staff issued followup RAI B.2.1.27-2 requesting that the applicant describe steps that are being taken to monitor the liner plate thickness around the transfer tube or efforts to address the leakage of borated water or both.

In its response, dated April 14, 2011, the applicant stated that the leak path into the fuel transfer tube vault has been repaired and the borated water leakage stopped. The area of the containment liner plate that had showed signs of deficiency (loss of material) have been examined and accepted by engineering evaluation. The areas are subject to IWE required augmented UT examinations for the next three exam cycles. If no further degradation (loss of material) is observed during those three cycles, the subject area will return to normal visual IWE inspections. These visual inspections would be able to identify any further leakage of borated water.

Based on its review, the staff finds the applicant's response to RAI B.2.1.27-2 acceptable because the applicant evaluated the local loss of thickness and degradation in the liner plate around the fuel transfer tube and found it acceptable. The applicant also identified this degradation in its ISI Program database for reexamination during the next three exam cycles in accordance with IWE-2420 requirements. In addition, the applicant repaired the leak path into the fuel transfer tube vault to stop the borated water leakage. The normal visual examinations and augmented UT examination of the affected area during the next three exam cycles in accordance with IWE requirements will ensure that the containment liner aging is managed in accordance with the guidance provided in GALL Report AMP XI.S1. The staff's concerns in RAI B.2.1.27-2 and the associated followup RAI are resolved.

Based on its audit and review of the application and review of the applicant's responses to RAIs RAI B.2.1.27-1 and RAI B.2.1.27-2, 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 also finds 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; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.27 provides the UFSAR supplement for the ASME Code Section XI, Subsection IWE Aging Management 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 3.5-2.

The staff also noted that the applicant committed (Commitment No. 50) to ongoing implementation of the existing ASME Code Section XI, Subsection IWE AMP for managing aging of applicable components during the period of extended operation. Specifically, the applicant committed to perform UT testing in the vicinity of moisture barrier for loss of material at a nominal 10° increment around the circumference of containment and to complete it no later than December 31, 2015. The UT testing will be repeated at intervals of no more than five RFOs. The applicant has also committed (Commitment 52) to keep the annular space between the containment and containment enclosure buildings in a dewatered state. The staff determined that the information in the UFSAR supplement, as amended, pending resolution of Open Item OI 3.0.3.1.9-1, 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 Code Section XI, Subsection IWE AMP, the staff finds all program elements consistent with the GALL Report. Also, the staff reviewed the enhancement and confirmed that its implementation through Commitment No. 50 prior to the period of extended operation (no later than December 31, 2015) would make the existing AMP consistent with the GALL Report AMP to which it was compared. However, the staff is concerned that, until now, the applicant has not implemented Commitment 52 to ensure that the annular space between the containment and containment enclosure buildings is maintained in a dewatered state. The staff's concern is tracked as Open Item OI 3.0.3.1.9-1.

3.0.3.1.10 ASME Code Section XI, Subsection IWF Program

Summary of Technical Information in the Application. LRA Section B.2.1.29 describes the existing ASME Code Section XI, Subsection IWF as consistent with GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF." In the LRA, the applicant stated that this program manages aging effects of the ASME Code Classes 1, 2, 3, and metal containment component supports. The Seabrook ASME Code Section XI, Subsection IWF Program is implemented on a 10-year cycle in accordance with the requirements of 10 CFR 50.55a, with specified limitations, modifications, and NRC-approved alternatives. The program specifies the percentage of supports that must be examined. For supports, other than piping supports, the supports of only one component of a group having similar design, function, and service are examined. The applicant also stated that the program uses VT-3 visual examination for detection of degradation and uses the acceptance standards for visual examination specified in ASME Code Section XI, Subsection IWF-3410.

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 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 Report AMP XI.S3. As discussed in the audit report, the staff confirmed that these elements are consistent with the corresponding elements of GALL Report AMP XI.S3. Based on its audit, the staff finds that elements one through six of the applicant's ASME Code Section XI, Subsection IWF Program are consistent with the corresponding program elements of GALL Report AMP XI.S3 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.29 summarizes operating experience related to the ASME Code Section XI, Subsection IWF Program. In the LRA, the applicant stated that an operating experience review found instances of supports being deficient but operable. These conditions were reported and evaluated in accordance with the Corrective Action Program. The LRA also states that IWF Program inspections in the spring of 1997 and spring of 1999 resulted in 36 and 5 deficiencies, respectively. The applicant stated that these conditions were evaluated and dispositioned. During the spring of 2005 inspection, no deficiencies requiring further evaluation were identified.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 plant operating experience information to determine if the applicant adequately incorporated and evaluated operating experience related to this program.

During its review, the staff identified 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. The staff determined the need for additional clarification, which resulted in the issuance of an RAI.

The GALL Report AMP XI.S3 states that the IWF scope of inspection for supports is based on sampling of the total support population. Discovery of support deficiencies during regularly scheduled inspections triggers an increase of the inspection scope in order to ensure that the full extent of the deficiencies is identified. IWF-2430 provides guidance on how to increase the sample size in case deficiencies are identified during examination of the supports. However, during the audit, the staff did not find any documentation that the supports sample size was increased in accordance with IWF-2430 after the ISI inspections conducted during 1997 and 1999, which identified 36 and 5 support conditions with deficient conditions, respectively. Therefore, to address this issue, by letter dated November 18, 2010, the staff issued RAI B.2.1.29-1 requesting the applicant provide documentation demonstrating IWF inspections are performed in accordance with the recommendations of GALL Report XI.S3 regarding increase in the sample size when deficiencies are identified during examination of supports.

In its response dated December 17, 2010, the applicant stated that during the 1997 IWF (RFO OR05) Inspection, 36 apparent deficiencies were identified. All 36 were evaluated by the applicant engineering personnel. Of the 36 deficiencies, 32 were suspect clearances that were found acceptable, 2 were determined to be design issues (which were corrected), and 2 were evaluated as deficiencies which were repaired to acceptable condition. For these last two deficiencies, the applicant conducted expanded inspections. The applicant also stated that the 32 clearance deficiencies noted above were identified on the basis of ISI drawings, which gave an absolute value for clearance. The applicant further stated that the engineering evaluation that evaluated the clearances against tolerances of the design and construction specifications, found the conditions to be nonrelevant in accordance with IWF-3410(b). Therefore, no corrective action was called for and an extended examination was not required. Similar results for clearance deficiencies were seen and dispositioned during the following, 1999 IWF Inspection.

The staff reviewed the applicant's response to the RAI B.2.29-1 and found it acceptable because the applicant expanded the scope of inspections for the two supports that were found deficient and repaired them, as required by ASME Code Section XI, Subsection IWE. The other supports with clearance deficiencies were found to be acceptable after review of design drawings. IWF-3410 considers general conditions that are acceptable by the material, design, or construction specifications as nonrelevant. Expanded scope, in accordance with IWF-3410, is not required for nonrelevant conditions. The staff's concern in RAI B.2.1.29-1 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B.2.1.29-1, 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; therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.29 provides the UFSAR supplement for the ASME Code Section XI, Subsection IWF 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 3.5-2. The staff determined 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 ASME Code Section XI, Subsection IWF Program and RAI B.2.1.29-1 response, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant 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 10 CFR Part 50, Appendix J Aging Management Program

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.30 describes the existing 10 CFR Part 50, Appendix J AMP as consistent with GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J." According to the applicant, this program is a containment leak rate monitoring program that includes integrated and local leak rate tests of components that make up the primary containment pressure boundary. The program includes Types A, B, and C

testing as described in 10 CFR Part 50, Appendix J and provides for periodic verification of the leak-tight integrity of the primary reactor containment. The applicant also stated that the Seabrook Station Leakage Test Reference is based on guidance provided in NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," and ANSI/ANS-56.8-1994, "Containment System Leakage Testing Requirements," with the restrictions identified in Regulatory Guide (RG) 1.163, "Performance-based Containment Leak-Test Program." The applicant further stated that its 10 CFR Part 50, Appendix J program, in conjunction with its ASME Code Section XI, Subsection IWE and ASME Code Section XI, Subsection IWL programs, provides an AMP that is effective at detecting degradation of the containment boundary.

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 Report AMP XI.S4. 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 Report AMP XI.S4, with the exception of the "detection of aging effects" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of RAIs.

GALL Report AMP XI.S4 recommends a containment leak rate testing program as an effective method for detecting degradation of containment shells, liners, and components that compromise the containment pressure boundary, including seals and gaskets. It also states that this would be achieved with the additional implementation of an acceptable containment ISI program as described in GALL Report AMPs XI.S1 and XI.S2. In addition, GALL Report AMP XI.S4 recommends a general inspection of internal and external surfaces of the containment prior to a Type A test. However, during its audit, the staff found that the applicant inspected containment surfaces prior to the most recent Type A test using its "Complex Procedure" for reactor containment integrated leakage rate testing. Based on a review of the procedure, the staff noted that the containment inspection section of the procedure does not specify examination methods for conducting internal and external inspections that are consistent with ASME Code Section XI, Subsections IWE and IWL requirements.

By letter dated December 14, 2010, the staff issued RAI B.2.1.30-1 requesting that the applicant:

- Describe the methods and procedures used to conduct a general inspection of internal and external surfaces of the containment prior to the most recent Type A test.
- Indicate whether these methods and procedures are consistent with the containment ISI programs described in GALL Report AMPs XI.S1 and XI.S2.
- Describe the method being used to ensure that internal and external containment inspections are being implemented as described in GALL Report AMPs XI.S1 and XI.S2 and consistent with element 4, "Detection of Aging Effects," of GALL Report AMP XI.S4.

In its response to RAI B.2.1.30-1, item 1, dated January 13, 2011, the applicant stated that the Type A test conducted in 2008 was performed using the "Reactor Containment Integrated Leakage Rate Test - Type A" complex procedure. According to the applicant, this procedure contains a prerequisite which states: "A general inspection of the accessible interior and exterior surfaces of the containment structure and components is complete." The inspection requires that:

> The structural integrity shall be determined by a visual inspection of the exposed accessible interior and exterior surfaces of the containment vessel. The inspection shall be performed to verify no apparent changes in appearance of the surfaces or other abnormal degradation. Any abnormal degradation of the containment vessel detected during the above required inspections shall be reported to the Commission in a Special Report pursuant to T.S. 6.8.2 within 15 days.

The applicant further stated that the general inspection of the accessible interior and exterior surfaces of the containment structure is a requirement from 10 CFR Part 50, Appendix J, Subsection V.A, and is in addition to, and totally separate from, the inspection requirements of ASME Code Section XI, Subsections IWE and IWL.

In response to RAI B.2.1.30-1, item 2, the applicant stated that the Seabrook Appendix J Program is consistent with the requirements of GALL Report AMP XI.S4 and that the containment inspection required by 10 CFR Part 50, Appendix J is in addition to and separate from the requirements of GALL Report AMP XI.SI and XI.S2. In response to item 3, the applicant stated that its XI.SI and XI.S2 programs are consistent with NUREG-1801 and that the inspections conducted as part of the 10 CFR Part 50, Appendix J Program are consistent with GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J."

The staff finds the applicant's response to the RAI B.2.1.30-1 acceptable because the applicant did not credit the IWE/IWL visual inspections towards Appendix J general visual examinations between and prior to Type A tests. The applicant performed a different set of inspections to meet the 10 CFR Part 50, Appendix J general visual inspection requirements prior to and between Type A tests. Therefore, visual inspections, conducted independent and separate from those recommended by GALL Report AMPs XI.S1 and XI.S2, are not required to be consistent with ASME Code Section XI, Subsections IWE and IWL requirements. The staff's concerns in RAI B.2.1.30-1 are resolved.

GALL Report AMP XI.S4 states that Appendix J provides two options, A and B, either of which can be chosen to meet the requirements of a containment leak rate testing program. Under Option A, all of the testing must be performed on a periodic interval. Option B is a performance-based approach. In LRA Section B.2.1.30, the applicant states that the Seabrook Station Containment Leakage Rate Testing Program, required by Seabrook Station Technical Specification (TS), implements Option B, and the Seabrook Station Leakage Test Reference is based on the guidance provided in NEI 94-01 and ANSI/ANS-56.8-1994 with the restrictions identified in RG 1.163.

During the audit of element 4, the staff reviewed the "Complex Procedure" for reactor containment integrated leakage rate testing and qualification guidance for personnel who conducted visual examinations of concrete containment surfaces. The staff concluded that the qualification of personnel who conduct visual examinations of concrete containment surfaces should be consistent with qualification provisions in IWA-2300 as required by 10 CFR 50.55a.

By letter dated December 14, 2010, the staff issued RAI B.2.1.30-2 requesting the applicant to provide plans and a schedule that will ensure that personnel who perform visual examinations of concrete containment surfaces to comply with the applicant's commitment to implement Option B for integrated leakage rate tests are qualified in accordance with IWA-2300 requirements, and that the applicant's 10 CFR Part 50, Appendix J AMP is consistent with GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J."

In its response dated January 13, 2011, the applicant stated that personnel performing the visual examinations of concrete surfaces prior to an integrated leak rate test are not qualified in accordance with IWA-2300 and that there is no requirement in 10 CFR 50.55a that Appendix J general visual inspection personnel be qualified per IWA-2300. The applicant further explained that this is a general inspection of the containment surface for any apparent degradation that would cause failure of the integrated leak rate test and because there are no requirements for inspector qualifications, the Appendix J AMP is consistent with GALL Report AMP XI.S4. The applicant also stated that personnel performing the visual examinations required by the ASME Code Section XI, Subsections IWE and IWL are qualified to the requirements of IWA-2300.

The staff reviewed the applicant's response to RAI B.2.1.30-2 and noted that the applicant did not provide any information about the qualification of the personnel performing the visual examination. In addition, the response did not provide any specific acceptance criteria for inspection of the containment interior and exterior surfaces. The lack of qualification requirements for personnel performing general visual examinations may impact the structure integrity and leak tightness of the concrete containment during the period of extended operation. Therefore, in a teleconference dated November 8, 2011, that staff discussed draft followup RAI B.2.1.30-2, requesting the applicant provide information about the qualification of the personnel performing the general visual inspection of the accessible interior and exterior surfaces of the containment system for structural deterioration which may affect the containment leak-tight integrity conducted prior to each Type A test, and at a periodic interval between the Type A tests. In addition, the staff requested the applicant provide the acceptance criteria used for these inspections.

In its formal response to draft followup RAI B.2.1.30-2 by letter dated November 17, 2011, the applicant stated that:

> Personnel performing the Type A pretest general visual inspection utilize the Containment and Containment Enclosure Surface Inspection procedure, and are qualified in accordance with the Qualification Guide, Engineering Support Personnel Training Program for Appendix J Engineer. The procedure provides qualitative criteria needed to detect structural problems that may affect either the containment structure leakage integrity or the performance of the Type A test.

The applicant also initiated a change to this procedure to clarify the current inspection practices as follows:

> During refueling outages when Subsection IWE inspections and the ILRT [Integrated Leakrate Test] are to be performed, both of the IWE and Appendix J examinations will be performed prior to the ILRT. The Appendix J Engineer will review the results of the most recent Subsection IWL inspections as well as any issues identified from the IWE inspections prior to conducting the Appendix J general visual inspection.
>
> During refueling outages when a Subsection IWE inspection is not performed, and the Appendix J general visual inspection is required, the Appendix J Engineer will review the results of the most recent Subsection IWE and IWL inspections and then perform a separate general visual inspection in accordance with the Containment and Containment Enclosure Surface Inspection procedure.

The staff finds the applicant's response to followup RAI B.2.30-2 acceptable because the personnel performing the visual examination of the containment as a part of Appendix J, Type A test program are qualified and trained to discover any evidence of structural deterioration which may affect structural integrity or leak tightness. Both 10 CFR 50, Appendix J and NEI 94-01 do not have any specific personnel qualification requirements for these inspections but state that the objective of the inspection is to identify structural deterioration that may affect containment leak-tight integrity. In addition, visual examination of the containment conducted for Appendix J, Type A test program will be complemented and informed by the detailed examinations performed in accordance with ASME Code Subsection IWE and IWL requirements.

Based on its audit and review of the applicant's responses to RAIs B.2.1.30-1 and B.2.1.30-2, the staff finds that elements one through six of the applicant's 10 CFR Part 50, Appendix J AMP are consistent with the corresponding program elements of GALL Report AMP XI.S4 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.30 summarizes operating experience related to the 10 CFR Part 50, Appendix J AMP. The applicant indicated that implementation of Option B for testing frequency is consistent with plant operating experience and described results of Types B and C local leak rate tests performed during Refueling Outages 9, 10, 11, and 12. Although these tests identified leakage from various isolation valves and containment on-line purge penetrations that required repair or replacement, the applicant stated that no major issues were found and that all as-left local leak rate test results for Refueling Outages 9, 10, 11, and 12 were acceptable. During the audit, the staff found that the most recent Type A test was completed in 2008 and that the results of this test were within 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. 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 Part 50, Appendix J AMP.

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 3.5-2. The staff determined 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 Part 50, Appendix J AMP, 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).

3.0.3.1.12 Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Program

Summary of Technical Information in the Application. LRA Section B.2.1.32 describes the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements Program as consistent with GALL Report 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 EQ Requirements Program will manage the aging effects of embrittlement, cracking, discoloration, or surface contamination leading to reduced insulation resistance or electrical failure of accessible cables and connections due to exposure to an adverse localized environment caused by heat, radiation, or moisture in the presence of oxygen. The applicant also stated that accessible electrical cables and connections exposed to adverse localized environments or ambient conditions in excess of 60-year service limiting environments will be visually inspected for signs of accelerated age-related degradation.

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 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 Report AMP XI.E1. As discussed in the audit report, the staff confirmed that these elements are consistent with the corresponding elements of GALL Report 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 EQ Requirements Program are consistent with the corresponding program elements of GALL Report AMP XI.E1 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.32 summarizes operating experience related to the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program. The applicant claimed that both plant-specific and industry-wide operating experience was considered in the development of the program, and these considerations ensure that the program would be an effective AMP for the period of extended operation. The following particular observations were cited by the applicant, including the operating experience cited in NUREG-1801, Chapter XI, Section E1:

- the shared experiences of plant operators in the NEI License Renewal Working Group
- the results from Seabrook's Corrective Action Program, in particular with respect to degraded cable insulation from localized areas of overheating
- Seabrook plant engineering guidelines for system walkdowns that prompt engineers to observe the condition of cable and connections

Furthermore, in a condition report, the applicant stated that a project was undertaken in 1998 and 1999 to reduce the infiltration of groundwater into plant buildings by injecting a hydrophobic material through to the outside of the building walls. The effort was only partially successful and was terminated when, tritium contamination above background was found in groundwater leaking into the containment annulus. The applicant performed a root cause evaluation and installed dewatering points in three locations around the plant. The staff noted that no recent events of water intrusion in cable trays and tunnels were identified. The staff performed an inspection of the -26 ft electrical tunnel cable tray room and observed no water on cable tray or cables.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 plant operating experience information to determine if the applicant adequately incorporated and evaluated operating experience related to this program. Further, the staff performed a search of regulatory operating experience for the past 10-year period through April 2010. Databases were searched using various key word searches and then reviewed by technical auditor staff.

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 corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.32 provides the UFSAR supplement for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements 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 3.6-2. The staff also noted that the applicant committed (Commitment No. 34) to implement the new Electrical Cables and Connections Not Subject To 10 CFR 50.49 EQ Requirements Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determined 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 EQ Requirements Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant 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).

3.0.3.1.13 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.2.1.33 describes the new Electrical Cables and Connections Not Subject To 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program as consistent with GALL Report 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 EQ Requirements Used in Instrumentation Circuits Program will manage the aging effects of reduced insulation resistance due to exposure to adverse localized environments caused by heat, radiation, or moisture in the presence of oxygen, causing increased leakage currents. The applicant also stated that this program applies to sensitive instrumentation cable and connection circuits with low-level signals in the in-scope portions of in-core neutron flux monitoring cable in the nuclear instrumentation system.

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 they are bounded by the conditions for which the GALL Report was evaluated.

During its review, the staff confirmed that high-voltage, low-level radiation monitoring system cables that are usually in-scope of GALL Report AMP XI.E2 are included in the EQ Program by reviewing EQ equipment data sheets. The staff compared elements one through six of the applicant's program to the corresponding elements of GALL Report AMP XI.E2. As discussed in the audit report, the staff confirmed that these elements are consistent with the corresponding elements of GALL Report 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 EQ Requirements Used in Instrumentation Circuits Program are consistent with the corresponding program elements of GALL Report AMP XI.E2 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.33 summarizes operating experience related to the Electrical Cables and Connections Not Subject To 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program. In the LRA, the applicant stated that Seabrook considers plant-specific and industry-wide operating experience. The applicant also stated that, in 2008, testing was performed on all in-core neutron flux monitoring cables and connections. The test results documented a less-than-expected insulation resistance reading between the inner and outer shield. The low insulation resistance reading was attributed to the connector design. The applicant further stated that the design issue was resolved, and retesting found the cable and connection to be acceptable.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 plant operating experience information to determine if the applicant adequately incorporated and evaluated operating experience related to this program. Further, the staff performed a search of regulatory operating experience for the past 10-year period through April 2010. Databases were searched using various key word searches and then reviewed by technical auditor staff.

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 corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.33 provides the UFSAR supplement for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits 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 3.6-2. The staff also noted that the applicant committed (Commitment No. 35) to implement the new Electrical Cables and Connections Not Subject To 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determined 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 EQ Requirements Used in Instrumentation Circuits Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant 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 Metal Enclosed Bus Program

Summary of Technical Information in the Application. LRA Section B.2.1.35 describes the new Metal Enclosed Bus (MEB) Program as consistent to GALL Report AMP XI.E4, "Metal Enclosed Bus." The applicant stated that the MEB Program is a new program that will manage the following aging effects of in-scope MEBs:

- loosening of bolted connections due to thermal cycling and ohmic heating
- hardening and loss of strength due to elastomer degradation
- loss of material due to general corrosion
- embrittlement, cracking, melting, swelling, or discoloration due to overheating or aging degradation

The applicant further stated that this new program will be implemented prior to entering the period of extended operation and inspection will be conducted at least once every 10 years after the period of extended operation. Aging management of the exterior housing and elastomers of the in-scope MEBs is included in the Structures Monitoring 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 if 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 Report AMP XI.E4. 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 Report AMP XI.E4, with the exception of the "detection of aging effects" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

In Seabrook basis document LRAP-E4, under the "detection of aging effect" element, the applicant states that the MEB Program will perform thermography inspections external to the MEBs to determine if the in-scope MEBs have loose connections due to thermal cycling and ohmic heating. The inspections will be performed on all accessible bus sections while the bus is energized. Normally, windows are installed on the MEB to facilitate these thermography inspections. The metal enclosed cover may mask the heat created by loosening of bus connections, and the temperature differences between bus connections may not be detected if windows are not installed on MEBs. During the LRA onsite audit in the week of October 21, 2010, the staff asked the applicant to clarify how the MEB connection inspections at Seabrook are effective in detecting loosening of bus connections using external thermography measurements. In a letter dated November 15, 2010, the applicant revised the MEB Program description to clarify that, if thermography is used to identify loose connections, the applicant will use inspection techniques that will provide accurate readings. In addition, the applicant added connection resistance measurements as an alternate method to determine if MEB connections are loose. The applicant revised LRA Appendix B, Section B.2.1.35 as follows:

> The internal portions of the in-scope metal enclosed bus enclosures will be visually inspected for aging degradation of insulating material and for cracks, corrosion, foreign debris, excessive bust buildup, and evidence of moisture intrusion. The bus insulation will be visually inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. The isolated phase bus conductor is not insulated. The internal bus supports will be visually inspected for structural integrity and signs of cracks. The accessible bus section will be inspected for loose connections using a thermography inspection technique that will provide accurate temperature readings of the bus bolted connection temperatures, such as through view ports. As an alternative to thermography, connection resistance measurements may be used to determine if the in-scope MEBs have loose connections due to thermal cycling and ohmic heating. The program requires that bolted connections be below the maximum allowed temperature for the application, and free of unacceptable visual defects.

The staff finds the applicant's supplement to LRA Section B.2.1.35 acceptable because it will be performing thermography (such as through view ports) that will provide accurate temperature readings of the bus bolted connections temperature compared to using thermography external to the MEB metal enclosed cover. The staff also finds that the connection resistance measurement, as an alternative to thermography, is acceptable to determine if the bus connections are loosening due to thermal cycling and ohmic heating because high resistance measurement will indicate that the bus connections are loosening. The inspection technique (thermography or resistance measurements) is consistent with that in GALL Report AMP XI.E4.

Based on its audit and review of the applicant's response in letter dated November 15, 2010, the staff finds that elements one through six of the applicant's MEB Program are consistent with the corresponding program elements of GALL Report AMP XI.E4 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.35 summarizes operating experience related to the MEB Program. The applicant stated that plant-specific and industry-wide operating experience was considered in the development of this program. The applicant also stated that the Institute of Nuclear Plant Operation (INPO) issued a Special Event Report, SER 5-09, "6.9-kV Non-segregated Bus Failure and Complicated Scram." The event report documents the catastrophic failure of a 6.9-kV non-segregated bus. The cause of the event was attributed to the overheating of the center bus bar at the flex connection. Seabrook performs periodic visual inspections and infrared thermography tests on all in-scope non-segregated buses and the isolated phase buses. In 2005, during the inspection of a non-segregated phase bus, white corrosion was found on a bolted connection surface near a flat washer. In addition, a green residue was noted on the surface area of the bus near the connection area. The applicant also stated that the connection was broken to facilitate a complete inspection of the connection for additional corrosion. The connection was remade and successfully tested. The same duct was also noted to have an expansion joint that was not sealing. The applicant corrected the deficiency.

The staff reviewed the operating experience, in the application and during the audit, to determine if 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 plant operating experience information to determine if the applicant adequately incorporated and evaluated operating experience related to this program. Further, the staff performed a search of regulatory operating experience for the past 10-year period through March 2010. Databases were searched using various key word searches and then reviewed by technical auditor staff.

During its review, the staff found no additional 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 the program 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 corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.35 provides the UFSAR supplement for the MEB 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 3.6-2.

The staff also noted that the applicant committed (Commitment No. 37) to implement the new MEB Program inspections once every 10 years, with the first inspection to be performed prior to entering the period of extended operation, in order to manage aging of applicable components.

The staff determined 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 MEB Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant 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 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program

Summary of Technical Information in the Application. LRA Section B.2.1.37 describes the new Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Program as consistent with GALL Report AMP XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," as modified by LR-ISG-2007-02. The applicant stated that the Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Program is a new, one-time testing program that will be used to verify that the aging effect of loosened bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation on the metallic portion of electrical cable connections does not require management. The applicant further 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.

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 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 the GALL Report 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 the GALL Report AMP XI.E6, with the exception of the "parameters monitored or inspected" program element. For this element, the staff determined that the need for additional clarification was required.

GALL Report AMP XI.E6, under the "parameters monitored or inspected" program element, states that a representative sample of electrical cable connections is tested. The technical basis for the sample selected is to be documented. The implementing document for the program will provide the technical basis for the sample selection with respect to both sample size and inspection locations. In the basis document, LRAP-E6, under the same program element, the Seabrook program performs tests on a representative sample of electrical cable connections. The monitoring includes loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. The applicant developed the technical basis for selecting samples of cable connections and documented it as Technical Report, LRTR-E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Sample Selection," Revision 1. During the audit, the staff found that the sample size was not included in LRTR-E6 Revision 1. During the break-out meeting, the staff discussed with the applicant its concerns that the sample size is not being included in the technical report. The applicant revised the technical report (LRTR-E6 Revision 2) to include the sample size such that the sample set shall include at least 20 percent of the connections for each category listed below or a minimum of 25 connections of each of the following categories:

- power (4.160 kV and 13.8 kV) crimped/bolted
- power (460 V and 480 V) crimped/bolted
- control (120 VAC [volts-alternating current] and 125 VDC [volts-direct current]) crimped/terminal board connection
- instrument (low voltage) crimped/terminal board connection

The staff reviewed the technical report revision and found that the sample size is consistent with current staff positions.

Based on its audit, and review of LRA Section B.2.1.37 and LRTR-E6, Revision 2, the staff finds that elements one through six of the applicant's Electrical Cable Connections Not Subject To 10 CFR 50.49 EQ Requirements Program are consistent with the corresponding program elements of GALL Report AMP XI.E6, as modified by final LR-ISG-2007-02 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.37 summarizes operating experience related to the Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Program. Although a new program, the applicant stated that plant-specific operating experience and industry-wide operating experience was considered in the development of this program. The applicant further stated that a review of plant-specific and industry-wide operating experience ensures that the one-time inspection corresponding to GALL Report AMP XI.E6, will confirm the absence or presence of age-related degradation of cable connections caused by thermal cycling, ohmic heating, corrosion, and oxidation. The applicant stated that Seabrook routinely performs infrared thermography tests on numerous pieces of equipment, including electrical connections, as part of the Preventive Maintenance Program. In 2002, during an infrared thermography inspection of a 480 volt circuit breaker, a hot connection was found. The connection was approximately 150 °F hotter than similar connections. Seabrook procedures required that the connection be corrected within 1 week. Infrared thermography was used to monitor the connection on a daily basis until corrective action could be taken. The applicant further stated that, in 2005, an infrared thermography inspection identified heating on three connections in a control panel. The connections were 30–50 °F higher than expected. Seabrook procedures require that this condition be corrected in 12 weeks. The hot connections were repaired. The connections were found to be tight, and the hot spot was attributed to defective connectors.

The staff reviewed operating experience information, in the application and during the audit, to determine if the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in accordance with the GALL Report. As discussed in the audit report, the staff conducted walkdowns, interviewed the applicant's staff, and reviewed onsite documentation provided by the applicant. The staff also conducted an independent search of the applicant's operating experience information to determine if the applicant adequately incorporated and evaluated operating experience related to this program. Further, the staff performed a search of regulatory operating experience for the period 2000 through April 2010. Databases were searched using various key word searches and then reviewed by technical auditor staff.

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 corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.37 provides the UFSAR supplement for the Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements 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 3.6-2, as modified by the applicant's implementation of LR-ISG-2007-02.

The staff also noted that the applicant committed (Commitment No. 39) to implement the new Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determined 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 Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report and LR-ISG-2007-02. The staff concludes that the applicant 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).

3.0.3.1.16 Environmental Qualification of Electric Components Program

Summary of Technical Information in the Application. LRA Section B.2.3.2 describes the existing EQ of Electric Components Program as consistent with GALL Report AMP X.E1, "Environmental Qualification (EQ) of Electric Components." The applicant also stated that the EQ Program manages component thermal, radiation, and cyclic aging through the use of 10 CFR 50.49(f) qualification methods. The applicant also stated that qualified lives are determined for equipment within the scope of the EQ Program, and appropriate actions such as replacement, refurbishment, or reevaluation are taken prior to the end of the qualified life of the equipment so that the aging limit is not exceeded. The applicant further stated that all EQ equipment is included within the scope of 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 if they are bounded by the conditions for which the GALL Report was evaluated. As part of a power uprate to increase generating capacity by 5.2 percent and as part of license renewal, the applicant updated EQ calculations for EQ electrical equipment. The staff reviewed a sample of these calculations to ensure that the design change adequately accounted for the power uprate and the extended qualified life for license renewal.

The staff compared elements one through six of the applicant's program to the corresponding elements of GALL Report 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 Report 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 Report AMP X.E1 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.3.2 summarizes operating experience related to the EQ of Electric Components Program. The applicant stated its program is an existing program and has been maintained by onsite engineering personnel since its inception. The applicant also stated that Seabrook has a comprehensive operating experience program that monitors industry issues/events and assesses these for applicability to its own operations.

The applicant listed samples of condition reports in LRA Section B.2.3.2 such as those listed below:

- reducing solenoid qualified lives based on temperature monitoring
- potential loss of the environmental seal due to the twisting of a transmitter's electronics housing
- potentially different greases being used on EQ fan motor bearings

The applicant stated the operating experience of the EQ Program did not show any adverse trend in performance. The applicant further stated the key elements of the EQ Program are being monitored and effectively implemented.

The staff reviewed the operating experience in the application and during the audit to determine if the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and 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 if the applicant adequately incorporated and evaluated operating experience related to this program. Further, the staff performed a search of regulatory operating experience for the past 10-year period through April 2010. Databases were searched using various key word searches and then reviewed by technical auditor staff.

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 corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.3.2 provides the UFSAR supplement for the EQ of Electric Components Program. The staff reviewed this UFSAR supplement description of the program and noted that, in conjunction with LRA Section 4.4, 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 determined 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 EQ of Electric Components Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant 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 Aging Management Programs Consistent with the GALL Report with Exceptions or Enhancements

In LRA Appendix B, the applicant stated that the following AMPs are, or will be, consistent with the GALL Report, with exceptions or enhancements:

- Reactor Head Closure Studs Program
- Steam Generator Tube Integrity Program
- Open-Cycle Cooling Water System Program
- Closed-Cycle Cooling Water System Program
- Inspection of Overhead Heavy Load Handling Systems Program
- Compressed Air Monitoring Program
- Fire Protection Program
- Fire Water System Program
- Aboveground Steel Tank Program
- Fuel Oil Chemistry Program
- Reactor Vessel Surveillance Program
- Selective Leaching of Materials Program
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program
- External Surfaces Monitoring Program
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program
- Lubricating Oil Analysis Program
- ASME Code Section XI, Subsection IWL Program
- Structures Monitoring Program
- Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program
- Protective Coating Monitoring and Maintenance Program
- Metal Fatigue of Reactor Coolant Pressure Boundary Program

For AMPs that the applicant claimed are consistent with the GALL Report, with exception(s) or enhancement(s) or both, the staff performed an audit and review 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 exception(s) or enhancement(s) to the GALL Report to determine if they were acceptable and adequate. The results of the staff's audits and reviews are documented in the following sections.

3.0.3.2.1 Reactor Head Closure Studs Program

Summary of Technical Information in the Application. LRA Section B.2.1.3 describes the existing Reactor Head Closure Studs Program as consistent, with an exception, with GALL Report AMP XI.M3, "Reactor Head Closure Studs." The applicant stated that the aging effects of reactor vessel flange stud hole threads, reactor head closure studs, nuts, and washers are detected through visual or volumetric examination in accordance with the applicant's ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to manage cracking and loss of material. The applicant also stated that the program implements the guidance outlined in RG 1.65, "Materials and Inspections for Reactor Vessel Closure Studs," for preventive measures including material selection, appropriate coatings, and lubricants. The applicant further stated that reactor head closure studs are manufactured from SA-540, Class 3, Grade B24 material. The applicant stated that these reactor head closure studs are coated with an anti-galling metallic coating (PlasmaBond), and a station-approved lubricant is used during installation and removal of the studs that does not contain molybdenum disulfide.

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 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 Report 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 Report AMP XI.M3, with the exception of the "preventive actions" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of RAIs.

In its review, the staff noted that RG 1.65 was originally issued in 1973. The staff also noted that RG 1.65, Revision 1, was issued in April 2010 and includes using bolting material for closure studs that has a measured yield strength less than 150 ksi, which is resistant to stress corrosion cracking. The staff further noted that LRA Section B.2.1.3 states that the applicant's reactor head closure studs are manufactured from SA-540, Class 3, Grade B24 material, and the maximum tensile strength of the material is less than 170 ksi, as recommended in the GALL Report and RG 1.65 issued in 1973. However, the staff noted that the applicant's program does not include the preventive action using stud materials with a measured yield strength level less than 150 ksi in comparison with RG 1.65, Revision 1. By letter dated December 14, 2010, the staff issued RAI B.2.1.3-1 requesting that the applicant clarify whether the measured yield strength of the reactor head closure stud material exceeds 150 ksi and clarify whether there are program provisions that would preclude use of materials with yield strength greater than 150 ksi. The staff also requested that, if the program does not include provisions that would preclude use of materials with yield strength greater than 150 ksi or if the reactor head closure stud material has a yield strength level greater than or equal to 150 ksi, the applicant justify why the Reactor Head Closure Studs Program is adequate to manage stress corrosion cracking in the high-strength material.

In its response dated January 13, 2011, the applicant committed (Commitment No. 53) to replace the reactor head closure stud(s) manufactured from the bar that has a yield strength greater than 150 ksi with ones that do not exceed 150 ksi prior to the period of extended operation. The applicant also stated that the yield strength from the test coupon for one of the bars, from which the studs were manufactured, was measured at 151.75 ksi, which is slightly higher than 150 ksi. The applicant further stated that the studs, which have yield strength measured at 151.75 ksi, are presently in storage. In addition, the applicant stated that its Reactor Head Closure Studs Program is revised to implement the guidance outlined in RG 1.65, Revision 1, such that its program includes the preventive action using stud materials with a measured yield strength not exceeding 150 ksi.

Based on its review, the staff finds the applicant's response to RAI B.2.1.3-1 acceptable for the following reasons:

- The applicant's Reactor Head Closure Studs Program is revised to implement the guidance of RG 1.65, Revision 1, for the use of material with yield strength not exceeding 150 ksi.
- The applicant committed (Commitment No. 53) to replace the reactor head closure studs with yield strength greater than 150 ksi, which are presently in storage, with the ones that do not exceed 150 ksi measured yield strength, consistent with the guidance in RG 1.65, Revision 1.
- The applicant's inspection, in accordance with the ASME Code Section XI, is adequate to detect and manage cracking due to stress corrosion cracking of the studs.

The staff's concern described in RAI B.2.1.3-1 is resolved.

The staff noted that the program description of GALL Report AMP XI.M3 states that the recommended program includes ISI to detect cracking, loss of material, and coolant leakage from reactor head closure studs. The staff also noted that the "preventive actions" program element of GALL Report AMP XI.M3 includes using manganese phosphate or other acceptable surface treatments and stable lubricants. LRA Section B.2.1.3 indicates that a station-approved lubricant is used during the installation and removal of the studs that does not contain molybdenum disulfide. The staff noted that the applicant's operating experience indicates that discoloration was reported on some of the reactor head closure studs during RFO 8 in 2002, and the discoloration on the PlasmaBond coating was determined to be the lubricant used for stud removal and was not considered an indication of stud degradation. By letter dated December 14, 2010, the staff issued RAI B.2.1.3-2, requesting that the applicant clarify the root cause for the discoloration on the closure studs. The staff also requested that the applicant provide the service temperature range of the lubricant in comparison with the operating temperatures of the reactor head closure studs. The staff further requested that the applicant clarify whether the lubricant is stable at the operating temperatures and is compatible with the stud and vessel materials and with the surrounding environment.

In its response dated January 13, 2011, the applicant stated that a condition report from 2002 identified slight surface rust and discoloration on the PlasmaBond metallic coating on the reactor head closure studs. The applicant also stated that the PlasmaBond vendor indicates that the discoloration was due to tarnishing of the silver in the metallic coating, that the rust was limited to a small area near the top of the threaded portion of the stud that threads into the reactor vessel flange, and that the slight coating of rust identified in 2002 appears to have come from the reactor vessel stud hole. The applicant stated that during RFOs when the reactor head closure studs are removed, the stud holes are cleaned to remove any particles or deposits that may have accumulated in the stud holes. The applicant also stated that the inspection of the studs revealed no thread damage, and the small amount of surface rust and discoloration on the PlasmaBond coating is not considered an aging effect that requires management during the period of extended operation. The applicant stated that the lubricant (WD-40) applied on the studs has an operating temperature range from -10 °F to 200 °F and the operating temperature of the reactor head closure studs is estimated to approach 500 °F. In addition, the applicant stated that according to the manufacturer of the lubricant, when the lubricant is exposed to the reactor vessel metal temperature at operating condition, it would carbonize and any carbonized deposits would have no adverse effect on the PlasmaBond coating or reactor vessel stud or flange materials.

The staff noted that the applicant’s lubricant is also used to clean the reactor head closure studs during RFOs and later to protect potential corrosion of the stud material. The staff further noted that the applicant claimed that its review of plant-specific operating experience indicates no adverse effect on the aging of reactor head closure stud or vessel flange materials. However, the staff finds the applicant’s response unacceptable because the operating temperature range of the lubricant (-10 °F to 200 °F) is significantly lower than the operating temperature of the reactor head closure studs that is estimated by the applicant to approach 500 °F. Additionally, the lubricant carbonizes at the operating temperature of the closure studs and the carbonization by-products may accumulate on the stud threads and cause bolting material degradations. The staff also noted that the applicant’s use of the lubricant is not consistent with the guidance in RG 1.65, that lubricants for the stud bolting are permissible provided they are stable at operating temperatures of the reactor head closure stud bolting. In addition, the staff was concerned that the carbonization of the lubricant and accumulation of carbonization by-products on the studs and flange threads degrade the lubrication process of the bolting such that the removal operation of the studs may cause sticking, galling, or thread damage of the reactor head closure bolting.

By letter dated February 24, 2011, the staff issued RAI B.2.1.3-2 followup. The staff asked the applicant to justify why the use of the lubricant, the operating temperature of which is significantly lower than that of the reactor head closure studs, is consistent with the guidance in RG 1.65 and the GALL Report, which state that lubricants for the stud bolting are permissible provided they are stable at operating temperatures of the reactor head closure stud bolting. The staff also requested that the applicant justify the use of the lubricant, which has an operating temperature range from -10 °F to 200 °F, on the reactor head closure studs, which has an operating temperature that is estimated to approach 500 °F. The staff further requested that, if a justification for the use of this lubricant cannot be provided, the applicant state the lubricant it will use that will remain stable at operating temperatures of the reactor head closure stud bolting. In addition, the staff requested that the applicant justify why the carbonization of the lubricant and accumulation of carbonization by-products on the studs and flange threads do not cause sticking, galling, or thread damage of the studs and flange threads and, as part of the justification, clarify whether the applicant’s operating experience is in agreement with the justification.

In its response dated March 22, 2011, the applicant stated that the LRA and its response to RAI B.2.3-2 incorrectly referred to WD-40 as a “lubricant” when, in fact, its intended use is to clean the reactor head closure studs and stud holes and protect them against rust and corrosion that can form at ambient temperatures, specifically, during installation and removal of the studs. The applicant also stated that the WD-40 product has been evaluated for use as an expendable product on external surfaces at its site with no restrictions. In addition, once the WD-40 is elevated to normal operating temperature of approximately 500 °F, the carbonized deposits have no adverse effect on the PlasmaBond coating, reactor vessel stud, or flange materials. The applicant further stated that it has not experienced sticking, galling, or thread damage of the studs or flange threads due to carbonization by-products associated with WD-40.

Based on its review, the staff finds the applicant's responses to RAIs B.2.1.3-2 and B.2.1.3-2 followup acceptable for the following reasons:

- The applicant's inspection results did not indicate thread damage on the reactor head closure studs associated with the discoloration, which was a result of tarnishing from the silver in the PlasmaBond coating.
- Any particle or deposit that may have accumulated in the stud holes will be removed during RFOs, so the potential of contamination or material accumulation is minimized on the stud and flange thread surfaces.
- The applicant clarified that WD-40 is only used to clean and protect the exposed areas of the studs and stud holes from corrosion that can form at ambient temperatures.
- The plant-specific operating experience indicates no occurrence of sticking, galling, or thread damage due to the use of WD-40.

The staff's concerns described in RAIs B.2.1.3-2 and B.2.1.3-2 followup are resolved.

The staff also reviewed the portions of the "detection of aging effects" program element associated with the exception to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this exception follows.

Exception 1. LRA Section B.2.1.3 states an exception to the "detection of aging effects" program element. The LRA states that the reactor head closure studs are removed from the reactor vessel during each RFO, and its ISIs are performed with the studs removed and consist of a volumetric examination only as allowed by Code Case N-307-3 and current version of the ASME Code Section XI.

The staff noted that the "detection of aging effects" program element of GALL Report AMP XI.M3 recommends surface and volumetric examinations for the reactor head closure studs when removed, which are based on the requirements in Table IWB-2500-1 of the 1995 Edition through the 1996 addenda of the ASME Code Section XI. The staff also noted that the applicant clarified that the later version of the ASME Code referenced by GALL Report AMP XI.M3 (ASME Code 2001 edition including the 2002 and 2003 addenda) has been updated to include the Code Case N-307-3 allowance that the surface examination may be eliminated. In its review, the staff also noted that RG 1.65, Revision 1, issued in April 2010, indicates that the use of Code Case N-307-3 was approved by RG 1.147, Revision 15, "Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1," issued in October 2007.

Based on its review, the staff finds this exception to the "detection of aging effects" program element acceptable because the applicant performs volumetric examination of reactor head closure studs consistent with RG 1.65, Revision 1, and the 2001 edition of the ASME Code Section XI, including the 2002 and 2003 addenda. Additionally, the inspection, in accordance with the ASME Code Section XI requirements, is adequate to detect and manage loss of material due to wear and cracking due to stress corrosion cracking.

Based on its audit and review of the applicant's response to RAIs B.2.1.3-1, B.2.1.3-2 and B.2.1.3-2 followup, the staff finds that elements one through six of the applicant's Reactor Head Closure Studs Program, with acceptable exception, are consistent with the corresponding program elements of GALL Report AMP XI.M3 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.3 summarizes operating experience related to the Reactor Head Closure Studs Program. The applicant stated that one reactor head closure stud was stuck due to galling during RFO 5 in 1997. The applicant also stated that the stud was cut out, and appropriate repairs and retests were performed per the requirements of the ASME Code Section XI. The applicant further stated that this operating experience prompted an investigation into suitable anti-galling compounds, which resulted in the application of an anti-galling metallic coating on the reactor head closure studs.

The applicant's operating experience also addressed the final post-tensioned elongation values of reactor head studs. The applicant stated that one reactor head closure stud was found out of specified elongation range by 0.002 in. during RFO 10 in 2005. The applicant also stated that an engineering evaluation was performed and that the preload induced by post-tensioning was below the designed range but was adequate to carry the reactor vessel pressure design loads. During the audit, the applicant further stated that the out-of-specification condition was a one-time operational occurrence and was not associated with aging of reactor head closure studs.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 plant operating experience information to determine if the applicant 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 corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. 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 noted that it conforms to the recommended description for this type of program, as described in SRP-LR Table 3.1-2. The staff determined 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 Head Closure Studs Program, the staff determined 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 determined 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 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 Steam Generator Tube Integrity Program

Summary of Technical Information in the Application. LRA Section B.2.1.10 describes the existing Steam Generator Tube Integrity Program as consistent, with exceptions, with GALL Report AMP XI.M19, "Steam Generator Tube Integrity." The applicant stated that the program manages the following aging effects:

- cracking due to intergranular attack, outer diameter stress corrosion cracking, PWSCC, and stress corrosion cracking
- loss of material due to general, crevice and pitting corrosion, erosion, fretting, and wear
- reduction of heat transfer due to fouling and wall thinning from flow-accelerated corrosion of the steam generator (SG) components

The applicant stated that the program manages the aging of steam generator (SG) tubes, tube plugs, and tube supports. The tubing material for the Seabrook SGs is thermally treated Alloy 600 material. The applicant reported that the current dominant degradation mode for thermally treated Alloy 600 tubing is wear.

The applicant stated that the program is based on NEI 97-06, Revision 2, "Steam Generator Program Guidelines," the response and commitment to GL 97-06, "Degradation of Steam Generator Internals," and Seabrook Technical Specifications (TS) 3/4.4.5, "Steam Generators," which ensure that the performance criteria for structural integrity, accident-induced leakage, and operational leakage are not exceeded. The applicant also stated that Seabrook has implemented the operational leakage limits found in NUREG-1431, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors."

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 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 Report AMP XI.M19. As discussed in the audit report, the staff confirmed that these elements are consistent with the corresponding elements of GALL Report AMP XI.M19.

The staff also reviewed the portions of the "scope of program" 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 this exception follows.

Exception 1. LRA Section B.2.1.10 states an exception to the "scope of program" program element. The GALL Report recommends that the applicant implement the SG degradation management program described in NEI 97-06, "Steam Generator Program Guidelines," Revision 1, to manage effects of aging on the SG tubes, plugs, sleeves, and tube supports. Alternatively, this program element states that the Steam Generator Tube Integrity Program is based on NEI 97-06, Revision 2. The applicant states that Revision 2 of NEI 97-06 does not reduce the functional requirements of Revision 1. In addition, the applicant states that NEI determined that Revision 2 is consistent with Technical Specification Task Force (TSTF)-449, Revision 4, "Steam Generator Tube Integrity." The applicant states that Seabrook implemented TSTF-449 with License Amendment 115 to the technical specifications in June 2007.

The staff reviewed this exception and the guidance document NEI 97-06, Revision 1, recommended by the GALL Report AMP. The staff has reviewed NEI 97-06, Revision 2, and has found the guidance document consistent with the GALL Report because it does not reduce the fundamental requirements found in Revision 1. In addition, Revision 2 contains updated operating experience relevant to ensure that tube integrity is maintained.

The staff finds this program exception acceptable and consistent with the one described in the GALL Report Section XI.M19 because NEI 97-06, Revision 2, does not reduce the fundamental requirements of Revision 1, which is recommended by the GALL Report AMP, and Revision 2 was determined to be acceptable since it is consistent with TSTF-449.

Based on its audit, the staff finds that elements one through six of the applicant's Steam Generator Tube Integrity Program, with acceptable exception, are consistent with the corresponding program elements of GALL Report AMP XI.M19 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.10 summarizes experience related to the Steam Generator Tube Integrity Program. The staff reviewed this information and interviewed the applicant's technical personnel to confirm that the applicable aging effects and industry and plant-specific operating experience have been reviewed by the applicant and are evaluated in the GALL Report. During the audit, the staff independently confirmed that the applicant had adequately incorporated and evaluated operating experience related to this program.

The staff reviewed the following regarding operating experience:

(1) Through Refueling Outage 13 (Fall of 2009), Seabrook Station has plugged a total of 173 tubes in the steam generators (A-34 tubes, B-25 tubes, C-50 tubes, and D-64 tubes).

(2) The Steam Generator degradation assessment for RFO 13 in the fall of 2009 identified operating experience at Vogtle Unit 1 where axial and circumferential outside diameter stress corrosion cracking was reported at the top of the hot leg tubesheet. Vogtle has Westinghouse Model F Steam Generators with Alloy 600 thermally treated tubing similar to Seabrook Station. Vogtle Unit 1 was the first U.S. plant to report axial outside diameter stress corrosion cracking at the top of the tube sheet in a Model F Steam Generator. Accordingly, this operating experience was incorporated into the implementation plan for RFO 13 as part of the steam generator inspections.

    Subsequently, an axial outside diameter stress corrosion cracking indication was found on one tube in Steam Generator "C" hot leg. The indication was approximately 0.2 inches below the top of the tube sheet and was 0.10 inches long. The tube was plugged on both the hot leg and cold leg sides.

(3) During RFO 12 in the spring of 2008, foreign objects were discovered in steam generator "B" during the inspection of the steam drum area. The root cause evaluation was performed, which concluded that the cause of the foreign objects being in the steam generator was inadequate foreign material exclusion controls of material used in steam generator "B" steam drum inspection. The root cause evaluation's recommended corrective action to prevent re-occurrence by revising the job plan for steam generator inspection to include a pre-use inspection of all materials brought into the steam

generators for concealed/loose foreign material. This corrective action has been implemented.

During its review of the LRA, the staff also identified operating experience that indicates the potential for degradation of the SG tube-to-tubesheet welds that could impact the applicant's program in adequately managing aging effects during the period of extended operation. By letter dated December 14, 2010, the staff issued RAI B.2.1.10-1 requesting that the applicant clarify whether the tube-to-tubesheet welds are included in the RCPB or if alternate repair criteria have been permanently approved. It also requested the applicant to provide a plant-specific AMP, along with the Primary Water Chemistry Program, or justify an alternative method to manage cracking due to PWSCC on the primary coolant side of steam generator tube-to-tubesheet welds since they are made from a nickel alloy.

In its response dated January 13, 2011, the applicant stated that its SG tube-to-tubesheet welds are not included in the RCPB because NRC has approved an alternate repair criteria for Seabrook. However, the applicant further stated that NRC has not yet permanently approved the alternate repair criteria. In the event that the NRC does not grant a permanent approval of the alternate repair criteria through a license amendment, the applicant's RCPB would revert back to include the tube-to-tubesheet welds. For such a scenario, the applicant also stated in its response that, unless an alternate repair criteria changing the ASME Code boundary is permanently approved by the NRC, or the applicant's SGs are replaced to eliminate PWSCC-susceptible tube-to-tubesheet welds, the applicant will submit a plant-specific AMP to manage the potential aging effect of cracking due to PWSCC at least 24 months prior to entering the period of extended operation. The plant-specific program will do one of the following:

(1) perform a one-time inspection of a representative sample of tube-to-tubesheet welds in all SGs to determine if PWSCC cracking is present and, if cracking is identified, resolve the condition through engineering evaluation justifying continued operation or repair the condition, as appropriate

(2) perform an analytical evaluation showing that the structural integrity of the SG tube-to-tubesheet interface is adequately maintaining the pressure boundary in the presence of tube-to-tubesheet weld cracking and ensure that the tube-to-tubesheet welds are not required to perform a reactor coolant pressure boundary function

After reviewing the applicant's response to RAI B.2.10-1, the staff finds that the approved temporary alternate repair criteria appropriately excludes the tube-to-tubesheet welds from RCPB on a temporary basis. The staff also noted that the applicant has submitted a license amendment request on April 10, 2012, to gain permanent approval from the NRC for an alternate RCPB that does not include the tube-to-tubesheet welds. The staff is currently reviewing this request; approval of such a request would eliminate the need to manage aging of the welds.

However, by teleconference on May 29, 2012, the staff requested that the applicant either provide the aging management program for the tube-to-tubesheet welds (which would address the 10 attributes of an aging management program) as part of its license renewal application or include the management of the tube-to-tubesheet welds as part of the steam generator aging management program. In addition, the staff requested that the applicant include the specific actions to be taken to address this issue (i.e., as identified in (1) and (2) above) as commitments in the UFSAR supplement. The staff also requested the applicant to clarify its plans for submitting the analytical evaluation in (2) above as a license amendment for NRC review and approval prior to redefining the pressure boundary and to include this action as part of its commitment in the UFSAR supplement.

The applicant indicated that it would provide additional information in a subsequent submittal. This issue is identified as Open Item OI 3.0.3.2.2-1.

By letter dated December 14, 2010, the staff issued RAI B.2.10-2 requesting that the applicant address foreign operating experience in SGs with similar design to that of Seabrook SGs, where cracking due to PWSCC has been identified in SG divider plate assemblies made with Alloy 600.

In addition, the staff requested that the applicant discuss the materials of construction of the Seabrook SG divider plate assemblies and an appropriate program to manage the potential aging effect if the divider plate assembly is made of Alloy 600 material.

In its response date January 13, 2011, the applicant stated that the Seabrook Westinghouse Model F SG divider plate and weld materials are Inconel (ASME-SB-168) Alloy 600/82/182. The applicant also stated that Seabrook will perform an inspection of each SG prior to entering the period of extended operation to assess the condition of the divider plate assembly unless operating experience or analytical results or both show that crack propagation into the RCS pressure boundary is not possible, then the inspections need not be performed. The applicant indicated that any evidence of cracking will be documented and evaluated under the Corrective Action Program.

After reviewing the applicant’s response to RAI B.2.10-2, the staff finds that it appears to give Seabrook the option of performing a one-time inspection or performing an analytical evaluation to assess potential crack propagation into the RCS pressure boundary. The staff discussed this concern with the applicant, and the applicant revised its response. In a letter dated March 22, 2011, the applicant amended its response to RAI B.2.10-2 by stating that Seabrook will perform a one-time inspection of the divider plate assembly and that any evidence of cracking will be documented and evaluated under the Corrective Action Program. The applicant also indicated that any inspection techniques used will be capable of detecting PWSCC in the SG divider plate assemblies and their associated welds. The staff finds the applicant’s plans to perform a one-time inspection of each SG to assess the condition of the divider plate assembly acceptable because any crack present in the assembly will be detected, evaluated, and entered into the Corrective Action Program. Additionally, the applicant committed to performing the inspection prior to the period of extended operation. However, the staff requested that the applicant also provide information regarding its one-time inspection of the divider plate assembly in its UFSAR Supplement.

Based on its audit, review of the application, and review of the applicant’s responses to RAIs, the staff finds that, pending resolution of OI 3.0.3.2.2-1, 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, pending resolution of OI 3.0.3.2.2-1, the “operating experience” program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.10 provides the UFSAR supplement for the Steam Generator Tube Integrity 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 3.1-2. The staff also noted that the applicant committed (Commitment Nos. 54 and 55) to enhance the Steam Generator Tube Integrity Program prior to entering the period of extended operation. Specifically, the applicant committed to the following:

- Commitment No. 54: Unless an alternative repair criteria changing the ASME Code boundary is permanently approved by the NRC, or the Seabrook steam generators are changed to eliminate PWSCC-susceptible tube-to-tubesheet welds, the applicant will submit a plant-specific AMP to manage the potential aging effect of cracking due to PWSCC at least 24 months prior to entering the period of extended operation.
- Commitment No. 55: Seabrook will perform an inspection of each steam generator to assess the condition of the divider plate assembly.

As discussed in the Operating Experience section above, the staff requested that additional information be included in the applicant's UFSAR Supplement to capture future actions associated with Commitments Nos. 54 and 55. The staff's finding regarding the adequacy of the UFSAR supplement, as required by 10 CFR 54.21(d), is pending resolution of OI 3.0.3.2.2-1.

Conclusion. The staff's finding and conclusion regarding the applicant's Steam Generator Tube Integrity Program is pending resolution of OI 3.0.3.2.2-1.

3.0.3.2.3 Open-Cycle Cooling Water System Program

Summary of Technical Information in the Application. LRA Section B.2.1.11 describes the existing Open-Cycle Cooling Water System Program as consistent, with an exception, with GALL Report AMP XI.M20, "Open-Cycle Cooling Water System." The applicant stated that the Open-Cycle Cooling Water System Program manages elastomer degradation, reduction of heat transfer, and loss of material due to erosion, corrosion, and fouling. The applicant also stated that the program relies on the implementation of the recommendations of NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The applicant stated that the program includes the following:

- surveillance and control of aging mechanisms
- tests to verify heat transfer
- routine inspection and maintenance of plant components
- system walkdowns to ensure compliance with the station's licensing basis
- a review of maintenance, operating, and training practices and procedures to ensure the effectiveness of established programs

The applicant stated that the micro- and macro-biological fouling is controlled by its Chlorine Management Program. The applicant further stated that a variety of inspection and testing methods are used including visual, eddy current, and ultrasonic tests on plant heat exchangers and piping.

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 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 Report AMP XI.M20. 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 Report AMP XI.M20, with the exception of the "scope of program" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

GALL Report AMP XI.M20 recommends that the program address the aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms. During its audit, the staff found that the applicant will manage hardening and loss of strength due to elastomer degradation. During onsite discussions, the applicant stated that this aging effect would be managed by visual inspections. However, the staff considers the detection of hardening or loss of strength due to elastomer degradation to be impractical without some type of physical manipulation of the components being managed. It was unclear how the Open-Cycle Cooling Water System Program would manage this aging effect by visual inspections only.

By letter dated December 14, 2010, the staff issued RAI B.2.1.11-1, requesting that the applicant provide the technical basis for how hardening and loss of strength due to elastomer degradation will be managed by the Open-Cycle Cooling Water System Program.

In its response dated January 13, 2011, the applicant provided changes to LRA Section B.2.1.11, which included physical or manual manipulation of elastomers to detect hardening and loss of strength due to elastomer degradation. The staff finds this response acceptable because the applicant's modification to its program includes new techniques that are appropriate for detecting the hardening and loss of strength of elastomers. The staff's concern described in RAI B.2.1.11-1 is resolved.

The staff also reviewed the portions of the "preventive actions" program element associated with the exception to determine if 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.2.1.11 states an exception to the "preventive actions" program element. The LRA states that the open-cycle cooling water system includes both unlined and lined piping. The applicant stated that the unlined materials used in the system include Inconel, copper-nickel, aluminum-bronze, and stainless steels, which were specifically selected for their resistance to the effects of salt water. The applicant stated that, because of the material resistance, the Open-Cycle Cooling Water System Program will be able to manage unlined piping as well as lined piping.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception because it has unlined piping in the open-cycle cooling water system. The staff noted that GALL Report AMP XI.M20 states that components are lined or coated to protect the underlying metal surfaces. The staff evaluated the materials used in the unlined portions of open-cycle cooling water system. The staff reviewed the corrosivity of the materials in seawater using the American Society for Metals (ASM) international data and noted that the cited materials have low corrosion susceptibility in seawater. The staff finds the program's exception acceptable because the materials used by the applicant are resistant to the aggressive cooling water environment and preclude the need for being lined or coated to protect the metal surface.

Based on its audit and review of the applicant's response to RAI B.2.1.11-1, the staff finds that elements one through six of the applicant's Open-Cycle Cooling Water System Program, with acceptable exception, are consistent with the corresponding program elements of GALL Report AMP XI.M20 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.11 summarizes operating experience related to the Open-Cycle Cooling Water System Program. The applicant stated that because of leakage problems, it had replaced the 90-10 CuNi tubing in the primary component cooling water system heat exchangers with titanium. According to the applicant, followup eddy current inspections have shown that the leakage problems had been resolved. The applicant also stated that it identified seawater intrusion through gaps in the service water cement-lined joints. The applicant stated it refurbished the joints with flexible rubber leak seals and that followup inspections had confirmed that the seals had been effective in preventing further corrosion.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 if the applicant adequately incorporated and evaluated operating experience related to this program. During its review, the staff identified operating experience for which it determined the need for additional clarification and resulted in the issuance of an RAI, as discussed below.

The Operating Experience section for this program noted that the aboveground cement-lined piping associated with the diesel generator heat exchangers had been replaced with Plastisol polyvinyl chloride (PVC)-lined carbon steel piping and that follow-up examinations had confirmed that the engineering design change was effective in preventing loss of material. However, based on information provided by Regional staff in late 2011, the PVC lining had degraded to the extent that it was missing in certain portions of the piping and, according to the applicant, pieces of the lining had detached and partially restricted flow to a diesel generator heat exchanger. As part of the normal Reactor Oversight Process, Regional staff followed up on the applicant's operability evaluation, root cause determination, and corrective actions associated with this event. The Regional staff subsequently documented a violation of very low safety significance (Green) for a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," for several aspects of the design change 93DCR003, which installed the PVC-lined piping. The Regional staff's inspection activities associated with this event are documented in Inspection Reports (IR) 443/2011004, dated November 4, 2011, and IR 443/2011005, dated February 14, 2012.

By letter dated December 12, 2011, the staff issued RAI B.2.1.11-2, requesting the applicant to describe the recent PVC lining degradation and to discuss any previous aging management activities that were performed to manage liner degradation prior to the event. In addition, the staff requested the applicant to describe corrective actions taken in response to this event and to provide any enhancements made to the AMP to ensure components' intended functions will not be impacted during the period of extended operation.

In its response dated February 7, 2012, the applicant described the PVC lining degradation event, including its associated root cause evaluation, discussed the previous aging management activities for this portion of the piping, and described the corrective actions taken as a result of this event. The applicant's evaluation identified two root causes for this event.

(1) A limited life design change was implemented in 1994 with no provisions to formally track the periodic verification of the coating condition. The PVC lining material had a 15-year service life.

(2) Oversight of the service water system was not adequate due to a lack of compliance with the system performance monitoring guideline requirements associated with the PVC-lined pipe.

With respect to previous aging management activities, the applicant stated that following its installation in 1994, the PVC-lined piping was inspected in each outage from 1996 through 2003 with no significant indications of liner degradation. However, inspection notes in 2002 stated there was a lack of adhesion of the liner to the pipe surface. After 2003, periodic inspection of the PVC-lined piping was discontinued in favor of a new long-term inspection strategy, which focused on the service water system as a whole, and the PVC-lined piping was not singled out for more frequent inspections. The next inspection of the PVC-lined piping was scheduled for the refueling outage in 2012.

With respect to corrective actions taken in response to this event, the applicant stated that a design change will be developed to replace the PVC-lined piping in 2012 with a corrosion-resistant, unlined material, and that the associated service water piping will be periodically inspected to verify adequate pipe wall thickness. In addition, as part of the extent of condition evaluation, the applicant assigned actions to evaluate the concrete-lined piping in the screen wash and circulating water systems to determine liner adequacy and to determine if other coatings used in the service water system have service life limitations. Further, the applicant stated that corrective actions have been assigned to revise the design control process to utilize the preventive maintenance process for inspections and replacement activities and to establish a process to ensure that monitoring and inspection programs comply with system performance monitoring guidelines and that long-term strategies comply with regulatory commitments such as GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The applicant concluded that since the AMP has provision for managing protective coatings, enhancements are not required.

The staff reviewed the applicant's response and noted that several corrective actions have not been implemented. With regard to the Open-Cycle Cooling Water System Program, the staff noted that the replacement of the PVC-lined piping is scheduled for later in 2012, and activities associated with the following items are still pending:

- implement a process to ensure that monitoring and inspection programs comply with performance monitoring guidelines
- implement a process to ensure that long-term strategies comply with GL 89-13,
- determine liner adequacy in the screen wash and circulating water systems
- determine if other coatings in the service water system have service life limitations

The staff considered completion of these activities as providing reasonable assurance that the program can adequately manage the detrimental effects of aging on SSCs within the scope of the program. As discussed above, the applicant's corrective action activities are being addressed through the Reactor Oversight Process; however, because these activities directly affect the Open-Cycle Cooling Water System Program, the staff considers that these activities should be captured in a commitment. During a teleconference on April 10, 2012, the applicant agreed to complete the above activities prior to the period of extended operation.

In fact, by letter dated April 26, 2012, the applicant revised its response to RAI B.2.1.11-2 by stating that it had completed implementation of the process to ensure that monitoring and inspection programs comply with system performance guidelines and that long-term strategies comply with commitments made for GL 89-13. Regarding the adequacy of the liner in the screen wash and circulating water systems, the applicant stated that both systems have cement lining similar to the service water system and that inspections of the lining are conducted through the Open-Cycle Cooling Water System program for those portions that are within the scope of GL 89-13, or otherwise, through the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program.

Regarding other coatings in the service water system that may have service life limitations, the applicant stated that an engineering evaluation in 1993 had determined Belzona products, which are polymeric materials used for lining and liner repairs, have an expected service life of 15 years. The applicant added that it had reviewed its operating experience database and had not identified failures of Belzona products due to exceeding its service life. The applicant stated that the extent of use of Belzona and polyurethane coatings has been identified and is being tracked in the Service Water Inspection and Repair Trending Program, and that preventive maintenance activities ensure that inspections are scheduled and tracked.

Regarding the replacement of the PVC-lined piping, the applicant added Commitment No. 69 to LRA Section A.3, "License Renewal Commitment List," to replace the PVC-lined diesel generator heat exchanger service water piping with pipe fabricated from AL6XN material, prior to the period of extended operation. The applicant noted that this material is treated as stainless steel and is included in the existing AMR item to be managed for aging for piping and fittings in LRA Table 3.3.2-37 for the service water system.

The staff finds the applicant's response to RAI B.2.1.11-2 acceptable because the applicant provided sufficient details of its corrective actions for process improvements and program changes that address the failure of PVC-lined piping. In addition, the applicant's commitment to replace the PVC-lined piping prior to the period of extended operation resolves the specific operating experience issue, because the replacement piping is not lined, the replacement material has low corrosion susceptibility to seawater, and the piping will be managed in the same manner as other stainless steel components in the system. The staff's concern described in RAI B.2.1.11-2 is resolved.

Based on its audit, review of the application, and review of the applicant's response to RAI B.2.1.11-2, 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 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 Open-Cycle Cooling 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 Tables 3.2-2, 3.3-2, and 3.4-2. The staff also noted that the applicant committed (Commitment No. 69) to replace the PVC-lined service water piping for the diesel generator heat exchanger prior to 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 Open-Cycle Cooling Water System Program, the staff determined 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 determined 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 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 Closed-Cycle Cooling Water System Program

Summary of Technical Information in the Application. LRA Section B.2.1.12 describes the existing Closed-Cycle Cooling Water System Program as consistent, with exceptions and an enhancement, with GALL Report AMP XI.M21, "Closed-Cycle Cooling Water System." The applicant stated that this program manages the aging effects of cracking due to stress corrosion cracking (SCC), loss of material due to general, crevice, pitting, and galvanic corrosion, and reduction of heat transfer due to fouling. The applicant also stated that the program scope includes the primary component cooling water system, emergency diesel generator jacket water cooling system, fire pump diesel engine glycol coolant system, control building air handling glycol coolant system, and thermal barrier cooling water system. The applicant stated that it uses either a hydrazine chemistry or a mixed glycol chemistry to control aging in the various closed-cycle systems. The applicant further stated that it implements EPRI 1007820, "Closed Cooling Water Chemistry Guideline, Revision 1," to monitor and control the cooling water chemistry. The applicant stated that it uses corrosion test coupons to check the effectiveness of the inhibitor and corrosion rates.

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 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 Report AMP XI.M21. 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 Report AMP XI.M21, with the exception of the "preventive actions" and "acceptance criteria" program elements. For these elements, the staff determined the need for additional clarification, which resulted in the issuance of RAIs.

The GALL Report AMP XI.M21 states that the closed-cycle cooling water system corrosion inhibitor concentrations should be maintained within the specified limits of the EPRI guideline. However, during its audit, the staff found that the applicant's diesel generator cooling water jacket system, (a blended glycol formulation) only has a pH Action Level 2, and does not identify an Action Level 1 for pH. Action levels are actions to be taken upon reaching a chemistry range level that is above the normal range level. It was not clear to the staff why the applicant's onsite guidelines for the diesel generator cooling water jacket is not consistent with the EPRI guideline by having two action levels for pH. By letter dated December 14, 2010, the staff issued RAI B.2.1.12-2 requesting that the applicant justify why the pH action levels for the diesel generator cooling water jacket are not consistent with those found in the EPRI guideline. In its response dated January 13, 2011, the applicant added Commitment No. 57 in LRA Appendix A, to revise the program documents to reflect the EPRI guideline's operating ranges and action level values for the diesel generator cooling water jacket pH. The staff finds this response acceptable because adding the pH Action Level 1, in accordance with the EPRI guideline, will ensure that the identification of pH levels outside the normal operating range will initiate appropriate actions. The staff's concern described in RAI B.2.1.12-2 is resolved.

The GALL AMP XI.M21 recommends that acceptance criteria for performance tests be based on system and component design basis requirements under the “acceptance criteria” program element. However, the applicant stated that it does not plan to use performance tests to confirm the effectiveness of the program and instead will rely upon corrosion coupons and internal visual inspections. The staff noted that the applicant’s “acceptance criteria” program element did not include criteria to evaluate the results from the corrosion coupon surveillances and visual inspections. By letter dated December 14, 2010, the staff issued RAI B.2.1.12-4 requesting that the applicant provide the acceptance criteria that will be used for the corrosion coupon and visual inspection surveillance activities.

Prior to responding to RAI B.2.1.12-4, the staff guidance in GALL Report Revision 2, AMP XI.M21A on conducting performance tests for the Closed-Cycle Cooling Water Program was removed. The current staff guidance in the GALL Report states that the Closed-Cycle Cooling Water Program includes (a) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the function of the equipment is maintained and such that the effects of corrosion are minimized, (b) chemical testing of the water, and (c) inspections to determine the presence or extent of corrosion and/or cracking. The “parameters monitored/inspected” program element of GALL AMP XI.M21A state that the program monitors water chemistry and the visual appearance of surfaces exposed to the water, and that corrosion monitoring by coupon testing may be included. The “detection of aging effects” program element of GALL AMP XI.M21A states that if visual inspections identify adverse conditions, additional examinations are conducted. In its response dated January 13, 2011, the applicant revised LRA Section B.2.1.12 to state that personnel completing inspections under the Closed-Cycle Cooling Water System Program will be trained to identify parameters associated with the aging effects being monitored by the program. The revised section referred to the EPRI training program, “Identification and Detection of Aging Issues,” and stated that it is supplemented with the EPRI “Aging Assessment Field Guide,” and “Aging Identification and Assessment Checklists for Mechanical Components.” The applicant stated that the nuclear industry has collected information on how to identify if an aging effect is occurring and has developed training programs on how to correlate the observed condition to a possible aging effect. The applicant also stated that this training will ensure that these inspections will adequately address potential aging effects and associated acceptance criteria for the in-scope material. The applicant further stated that adverse or potentially adverse conditions identified during the visual inspections will be documented and evaluated in accordance with the corrective actions program and that system components must meet design requirements such as minimum wall thickness. The staff finds this response acceptable because:

- the Closed-Cycle Cooling Water Program includes visual inspections,
- inspectors are trained to observe for visual indications of adverse or potentially adverse conditions using industry standard guidelines,
- adverse or potentially adverse conditions will be evaluated under the corrective action program,
- the acceptance criterion for the evaluations is that system components must meet design requirements such as minimum wall thickness, and
- as allowed by SRP-LR A.1.2.3.6, it is not necessary to discuss CLB design loads if the acceptance criteria of the inspections do not permit degradation.

Given that GALL Report Revision 2, AMP XI.M21A recommends that corrosion coupon testing is an option in addition to visual inspections and the applicant's response is consistent with GALL AMP XI.M21A and the SRP-LR, the staff's concern described in RAI B.2.1.12-4 is resolved.

The GALL Report AMP XI.M21 states that the Closed-Cycle Cooling Water System Program includes preventive measures, testing, and inspection to both minimize and monitor corrosion. The GALL Report indicates that closed-cycle cooling water systems can undergo aging due to loss of material from microbiologically-influenced corrosion. The applicant's program states that it manages cracking due to SCC; loss of material due to general, crevice, pitting, and galvanic corrosion; and reduction of heat transfer due to fouling. However, it was not clear if the applicant uses the Closed-Cycle Cooling Water System Program to manage aging from microbiologically-influenced corrosion. By letter dated January 21, 2011, the staff issued RAI B.2.1.12-7 requesting that the applicant justify why the Closed-Cycle Cooling Water System Program does not need to manage microbiologically-influenced corrosion in the closed-cycle cooling water systems. The applicant was further requested to identify what preventive actions, parameters monitored or inspection techniques are being conducted if microbiologically-influenced corrosion is being managed by the Closed-Cycle Cooling Water System Program. In its response dated February 18, 2011, the applicant stated that the GALL Report, Revision 1 and Revision 2, did not include any items for PWRs; therefore, it did not consider microbiologically-influenced corrosion to be an aging effect requiring management. The applicant reiterated that the Closed-Cycle Cooling Water System Program does not manage loss of material for this mechanism. However, the applicant also stated that its closed-cycle cooling chemistry control procedure does include biological activity as a recommended parameter in keeping with the EPRI guideline. In addition, the applicant stated that its review of plant-specific operating experience did not identify any microbiologically-influenced corrosion issues in the close-cycle cooling water systems.

In its review of the applicant's response, the staff noted that microbiologically-influenced corrosion is a stated concern in the EPRI guideline for closed-cycle cooling systems using glycol formulations, and since these systems can be found in both boiling-water reactors (BWRs) and PWRs, the applicant's determination that this aging mechanism was not applicable to PWRs is without merit. The staff noted that the applicant's lack of plant-specific operating experience associated with microbiologically-influenced corrosion may be attributable to the existing additives that mitigate this mechanism. However, SRP-LR Section A.1.2.1, "Applicable Aging Effects," states the following:

> An aging effect should be identified as applicable for license renewal even if there is a prevention or mitigation program associated with that aging effect. For example, water chemistry, a coating, or use of cathodic protection could prevent or mitigate corrosion, but corrosion should be identified as applicable for license renewal, and the AMR should consider the adequacy of the water chemistry, coating, or cathodic protection as an aging management program.

Given this basis, the applicant did not provide reasonable assurance that loss of material due to microbiologically-influenced corrosion does not need to be included as part of the Closed-Cycle Cooling Water System Program. By letter dated May 23, 2011, the staff issued RAI B.2.12-9 requesting that the applicant provide plant-specific data to demonstrate that the lack of microbiologically-influenced corrosion cannot be attributed to the existing chemical treatment in the closed cooling water systems.

In its response dated June 2, 2011, the applicant stated that its program complies with the EPRI 1007820, "Closed Cooling Water Chemistry Guideline." The applicant also stated that it takes no exception relative to testing for microbiological activity and that its operating procedures include testing for biological activity as a diagnostic parameter. The applicant revised LRA Sections A.2.1.12 and B.2.1.12 to state that glycol containing systems within the scope of the Closed-Cycle Cooling Water System Program are monitored for the presence of microbiological activities in accordance with the EPRI Closed Cooling Water Chemistry Guideline. The staff finds this response acceptable because the applicant has modified its program documents to clarify that glycol systems are being managed for microbiologically-influenced corrosion, consistent with EPRI guidelines. The staff's concerns described in RAIs B.2.1.12-7 and B.2.1.12-9 are resolved.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with exceptions and an enhancement to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions and an enhancement follows.

Exception 1. LRA Section B.2.1.12 states an exception to the "preventive actions," "monitoring and trending," and "acceptance criteria" program elements. The applicant stated that it took an exception to the use of the EPRI TR-107396, "Closed Cooling Water Chemistry Guideline," that was issued in 1997, because it uses the updated version, EPRI 1007820, "Closed Cooling Water Chemistry Guideline, Revision 1," which was issued in 2004. The applicant stated that the updated version meets the same requirements of EPRI TR-107396 for maintaining conditions to minimize corrosion and microbiological growth.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception because the GALL Report is based on the earlier version of the EPRI guideline rather than the one used by the applicant. The staff finds the program exception acceptable because the updated EPRI guideline for the closed cooling water chemistry accounts for more recent operating experience and specifies equivalent guidance for corrosion inhibitor concentrations as those specified in TR-107396.

Exception 2. LRA Section B.2.1.12 states an exception to the "preventive actions," "monitoring and trending," and "acceptance criteria" program elements. The applicant stated that instead of limiting the normal operating range for hydrazine to the EPRI guidance maximum concentration of 200 ppm, the thermal barrier cooling water system is specified with a maximum of 300 ppm. The applicant also stated that this higher limit was established to minimize radiation exposure, which resulted from an ongoing hydrazine consumption issue apparently due to an unvented air problem. The applicant further stated it had determined that the higher concentration level was acceptable, based on a review of the potential effects on components, which included corrosion rate monitoring through corrosion coupons in the system.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception because an ongoing operational problem had caused more frequent chemical additions, resulting in increased worker radiation exposure. However, the applicant's technical basis documents did not discuss how copper corrosion was evaluated or the basis for why it is appropriate to have a higher hydrazine levels in its thermal barrier system than recommended in the EPRI guideline. The staff noted that the EPRI guideline discussed the susceptibility to SCC of some copper alloys exposed to ammonia, which can occur when hydrazine is exposed to air. By letter dated December 14, 2010, the staff issued RAI B.2.1.12-1 requesting that the applicant provide justification for the higher hydrazine levels in the thermal barrier system compared to what is recommended in the EPRI guideline and why these higher levels will not lead to enhanced degradation. In addition, the staff requested that the applicant provide information of the effect on aging if hydrazine concentrations were to increase above the normal operating range in the EPRI guideline during the period of extended operation.

In its response dated January 13, 2011, the applicant added Commitment No. 56 to LRA Appendix A, to revise the program documents to reflect the EPRI guideline operating ranges and action level values for hydrazine. Consequently, the applicant deleted Exception 2 from this AMP in the LRA, since an exception was not being taken. The applicant also stated that it evaluated the significance of allowing the system to operate with the higher hydrazine levels and determined it to be acceptable. Similarly, the applicant stated that it routinely monitored the operation during elevated ranges, and there were no indications of system of component degradation. In its review of this response, the staff did not consider that there was sufficient information regarding how the monitoring during elevated hydrazine levels had determined there were minimal long-term aging effects of copper components in the thermal barrier system.

By letter dated March 7, 2011, the staff issued RAI B.2.1.12-8 requesting that the applicant provide the technical information that describes why the elevated levels of hydrazine will not have caused accelerated aging of the components in the thermal barrier system that could affect component functions during the period of extended operation. The applicant was also asked to provide information on the AMP that will be used to manage the accelerated aging if it is determined that the elevated levels of hydrazine may have caused accelerated aging.

In its response, dated April 5, 2011, the applicant stated the higher sulfate and hydrazine levels were not expected to increase the corrosion rate of any copper alloys because the thermal barrier system is an all ferrous design. The applicant stated that the increased level of hydrazine and sulfate would not lead to an increased corrosion rate for either stainless steel or carbon steels because the higher level of hydrazine would lead to a low oxygen concentration and low electrochemical potential for stainless steel components. The staff finds this response acceptable because the applicant clarified that there are no copper components that could have an increased corrosion rate due to the higher level of ammonia. In addition, the staff noted that the higher levels of hydrazine will decrease the concentration of oxygen, which will lead to a decreased corrosion rate for carbon alloys. The staff further noted that a lower oxygen level will also reduce the electrochemical potential of any stainless steel components, which will reduce the likelihood of SCC even at the higher levels of sulfate for the temperature normally observed in the thermal barrier system. The staff's concern described in RAIs B.2.1.12-1 and B.2.1.12-8 is resolved.

Exception 3. LRA Section B.2.1.12 states an exception to the "preventive actions" and "monitoring and trending" program elements. The applicant stated that the EPRI guideline specifies Action Level 1 for sulfates as a concentration greater than 150 ppb. The applicant further stated that the thermal barrier cooling water system has an Action Level 1 of 500 ppb.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception regarding the higher limit to the sulfate operating range because the previous EPRI guideline did not specify this value. The applicant further stated that it evaluated the significance of operating the system at the higher concentration level and determined it to be acceptable because of lower oxygen levels, alkaline pH, and absence of sulfides in the thermal barrier cooling water system. However, the applicant's technical basis documents did not justify why it is appropriate to have higher sulfate levels in its thermal barrier system than is recommended by the EPRI guideline. By letter dated December 14, 2010, the staff issued RAI B.2.1.12-1 requesting that the applicant justify the higher sulfate levels in the thermal barrier system compared to those recommended in the EPRI guideline, and to discuss why these higher levels will not lead to enhanced degradation. In addition, the staff requested that the applicant provide information for the effects on aging if sulfate concentrations were increased above the action level in the EPRI guideline during the period of extended operation.

In its response dated January 13, 2011, the applicant added Commitment No. 56 to LRA Appendix A, to revise the program documents to reflect the EPRI guideline operating ranges and action level values for sulfates. Consequently, the applicant deleted Exception 3 to this AMP in the LRA, since an exception was no longer being taken. The evaluation of the potential for elevated sulfate levels in the past to have accelerated aging effects was included in RAIs B.2.1.12-1 and B.2.1.12-8, and the staff's findings are discussed above in the evaluation for Exception 2.

Exception 4. LRA Section B.2.1.12 states an exception to the "parameters monitored or inspected" and "monitoring and trending" program elements. The applicant stated that the EPRI guideline indicates that hydrazine concentrations and pH should be monitored weekly. In contrast, the applicant stated that, for the thermal barrier cooling water system, it would monitor hydrazine and pH monthly to reduce worker radiation exposure. The applicant further stated that recent system data trends show that hydrazine concentration and pH remained stable between the monthly samples, which demonstrates that monthly monitoring frequency is sufficient.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception because the thermal barrier cooling water system is located inside containment, and monitoring monthly would reduce the radiation exposure. The staff reviewed the hydrazine and pH data trends during the audit, which showed that these parameters are stable and predictable. The staff finds this program exception acceptable because the hydrazine data trends indicate that a monthly measurement rate is frequent enough to maintain the hydrazine within acceptable bounds.

Exception 5. LRA Section B.2.1.12 states an exception to the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. The applicant stated that it does not rely on performance and functional testing to verify the effectiveness of chemistry controls and managing aging effects, as stated in the GALL Report. Instead, the applicant stated that it monitors program effectiveness through internal inspections of opportunity and through corrosion monitoring by trending normal plant periodic samples and by evaluating system corrosion coupons.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception because it considered the performance and functional testing to fall under the maintenance rule. However, it was not clear to the staff whether the applicant was crediting maintenance rule activities to manage aging effects in the closed-cycle cooling water system during the period of extended operation and, if so, how these activities are captured in an AMP. By letter dated December 14, 2010, the staff issued RAI B.2.1.12-3 requesting that the applicant explain how the maintenance rule activities are included in the aging management of the closed-cycle cooling water systems during the period of extended operation.

In its response dated January 13, 2011, the applicant stated that the maintenance rule activities are not being credited to manage aging effects in the closed-cycle cooling water system during the period of extended operation. The applicant stated that it modified its program to remove the reference to the maintenance rule and that the performance monitoring is part of the engineering program that verifies the component active functions. The staff finds this response acceptable because the applicant modified its program to remove documentation that reports the maintenance rule is part of the activities for managing aging in the closed-cycle cooling water systems. The staff's concern described in RAI B.2.1.12-3 is resolved.

The staff also examined the use of corrosion coupons, and it was not clear from the basis documents that the corrosion coupons would be placed in a condition representative of the most detrimental environment for a given closed-cycle system (highest temperature, stagnant conditions, etc.). In addition, it was not clear if the corrosion coupons would be stressed, which is necessary to evaluate SCC. By letter dated December 14, 2010, the staff issued RAI B.2.1.12-5 requesting justification on how the corrosion coupons will represent high susceptible material and environmental conditions observed in a closed-cycle cooling water system. The applicant was also asked to provide additional information on why the corrosion coupons are adequate to evaluate SCC susceptibility.

In its response dated January 13, 2011, the applicant stated corrosion coupon monitoring will be used to assess the effectives of the corrosion inhibitors by quantifying the corrosion rates of the coupons. The applicant stated that the current location in the coupons in the closed-cycle cooling water system is appropriate for monitoring the effectiveness of corrosion inhibitors. The applicant further stated that the corrosion coupons are not pre-stressed and are not used for monitoring SCC. The applicant stated that SCC will be evaluated by conducting visual inspection of individual components for evidence of pitting, general corrosion film presence, biological activities, deposits, and SCC. The staff finds the response and program exception acceptable because the applicant has modified the program to indicate that SCC will be managed by visual inspections, and the corrosion coupons are placed in the appropriate locations to evaluate the effectiveness of corrosion inhibitors. The staff's concern described in RAI B.2.1.12-5 is resolved.

Enhancement 1. LRA Section B.2.1.12 states an enhancement to the "detection of aging effects" program element. The applicant stated that the program will be enhanced to include visual inspections for cracking, loss of material, and fouling in the primary component cooling water system, thermal barrier cooling water system, diesel generator jacket water cooling system, fire water pump diesel engine coolant system, and control building air handling coolant system.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M21. The staff noted that the GALL Report AMP states that the extent and schedule of inspections and testing should assure detection of corrosion or SCC before the loss of the intended function of the component. The staff finds the applicant's enhancement acceptable because it provides an alternative technique to verify the effectiveness of the control of water chemistry to manage aging in the closed-cycle cooling water systems.

Based on its audit, and review of the applicant's responses to RAIs B.2.1.12-1, B.2.1.12-2, B.2.1.12-3, B.2.1.12-4, B.2.1.12-5, B.2.1.12-7, B.2.1.12-8 and B.2.1.12-9, the staff finds that elements one through six of the applicant's Closed-Cycle Cooling Water System Program, with acceptable exceptions and an enhancement, are consistent with the corresponding program elements of GALL Report AMP XI.M21 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.12 summarizes operating experience related to the Closed-Cycle Cooling Water System Program. The applicant stated that, in 2003, the chemistry department identified that the hydrazine consumption in the thermal barrier cooling water system had significantly increased since the fall of 2000. The applicant stated that an investigation identified potential air entrapment in the thermal barrier cooling water system. The applicant stated that it statically and dynamically vented the thermal barrier cooling water system, which resolved the issue. In addition to this one operating experience, the applicant stated that, in 2003, it reviewed industry operating experience about an issue with cracking of brass bolting in the diesel generator jacket water cooling system. The applicant further stated that this evaluation showed that Seabrook uses a glycol mixture, which is similar in constituents to the industry operating experience conditions but that Seabrook uses a much higher concentration. The applicant stated that this evaluation concluded that Seabrook's tolytriazole dosage levels are sufficient to minimize brass degradation. The applicant also stated that this evaluation shows it uses industry experience to challenge existing program practices and validates existing program procedures through experiences or standards applied at other nuclear power plants.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 if the applicant adequately incorporated and evaluated operating experience related to this program. During its review, the staff identified 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. The staff determined the need for additional clarification, which resulted in the issuance of an RAI.

In LRA Section B.2.1.12, the applicant stated that it had addressed operating experience related to the closed-cycle cooling water systems. However, the staff found that the applicant had not addressed a recurring condition in the primary component cooling water system, where loss of material downstream of valves was causing cavitation erosion from throttling. The applicant stated it had conducted flow rebalancing to alleviate the concern. However, it was unclear to the staff how the applicant has re-evaluated these areas after flow rebalancing was conducted to determine whether loss of material due to cavitation erosion remains an issue in the primary component cooling water system. By letter dated December 14, 2010, the staff issued RAI B.2.1.12-6 requesting that the applicant provide additional information on how the loss of material due to cavitation erosion was confirmed to have been eliminated (i.e., inspection, etc.). If loss of material for this mechanism is still an applicable aging issue, the applicant was asked to provide information on how this aging effect is being managed.

In its response dated January 13, 2011, the applicant stated that it will conduct an inspection for loss of material prior to entering the period of extended operation. The applicant stated that the inspection will be performed during the 10-year period prior to the period of extended operation. The staff finds this response acceptable because the applicant will conduct an inspection to determine if the flow rebalancing has eliminated the cavitation-induced wear. However, the staff considers that these activities should be captured in a commitment, and during a teleconference on April 10, 2012, the applicant agreed to revise its response to RAI B.2.1.12-6. By letter dated April 26, 2012, the applicant added a new commitment (Commitment No. 70) to inspect the piping downstream of valves CC-V-444 and CC-V-446 within 10 years prior to the period of extended operation to determine whether the loss of material due to cavitation-induced erosion has been eliminated. The staff's concern described in RAI B.2.1.12-6 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B.2.1.12-6, 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; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.12 provides the UFSAR supplement for the Closed-Cycle Cooling 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 Tables 3.1-2, 3.2-2, 3.3-2, and 3.4-2.

The staff also notes that the applicant committed (Commitment Nos. 2, 56, 57, and 70) to enhance and revise the Closed-Cycle Cooling Water System Program prior to entering the period of extended operation. Specifically, the applicant committed to enhance the program to include visual inspection for cracking, loss of material, and fouling when the in-scope systems are opened for maintenance; to revise program documents to reflect EPRI Guideline operating ranges and action levels for hydrazine, sulfates, and diesel generator cooling water jacket pH; and to confirm that loss of material due to cavitation erosion has been eliminated in the 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).

Conclusion. On the basis of its audit and review of the applicant's Closed-Cycle Cooling Water System Program, the staff determined 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 determined that the AMP, with the exceptions, 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 Nos. 2, 56, 57, and 70 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).

3.0.3.2.5 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program

Summary of Technical Information in the Application. LRA Section B.2.1.13 describes the existing Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program as consistent, with enhancements, with GALL Report AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems." The applicant stated that the program manages the aging effects of loss of material due to general corrosion on structural steel members, components, and rails of the in-scope cranes and the aging effects of loss of material due to wear on the rails in the rail system. The applicant also stated that the program conducts visual inspections to identify aging effects prior to loss of function in accordance with its Lifting System Manual. The applicant further stated that these inspections are conducted yearly and documented on work orders.

<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 if 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 Report AMP XI.M23. As discussed in the audit report, the staff confirmed that these elements are consistent with the corresponding elements of GALL Report AMP XI.M23.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements associated with the enhancements to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

<u>Enhancement 1</u>. LRA Section B.2.1.13 states an enhancement to the "scope of program" and "parameters monitored or inspected" program elements. The LRA states that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program's Lifting System Manual will be enhanced to include monitoring of general corrosion on the crane and trolley structural components and the effects of wear on the rails in the rail system.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M23 and noted that GALL Report AMP XI.M23 recommends that the program manage general corrosion on the crane and trolley structural components and the effects of wear on the rails in the rail system. The staff finds the program enhancement acceptable because, when implemented, the program elements will be consistent with the recommendations in GALL Report AMP XI.M23.

<u>Enhancement 2</u>. LRA Section B.2.1.13 states an enhancement to the "scope of program" and "detection of aging effects" program elements. The LRA states that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program's Lifting System Manual will be enhanced to list additional cranes related to the refueling handling system.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M23. During the audit, the staff reviewed the applicant's AMP basis document for the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program and noted that the Lifting System Manual will be enhanced to list all in-scope cranes for periodic inspections. This enhancement will ensure that the effects of aging will be managed, consistent with the CLB, for the period of extended operation. The staff finds the program enhancement acceptable because, when implemented, the program elements will be consistent with the recommendations in GALL Report AMP XI.M23.

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 Report AMP XI.M23 and, therefore, are acceptable.

<u>Operating Experience</u>. LRA Section B.2.1.13 summarizes operating experience related to the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program. The applicant stated that there has been no history of corrosion-related degradation that has impaired cranes, and preventive maintenance work orders are used for tracking, identifying, and maintaining crane structural components of lifting systems and crane rail systems. During the audit, the staff reviewed an operating experience example described in a

condition report, indicating that the bus work track of the filter cask monorail hoist system was severely pitted from excessive corrosion. The staff reviewed the applicant's inspection findings and found that, during the inspection, corrosion was not observed on the rails and structural components of the system, which are the portions of the system within the scope of this program. The applicant initiated a preventive maintenance work order, conducted a root cause analysis, and replaced the bus track with a corrosion-resistant material, thus demonstrating proper management and implementation of the program.

The staff reviewed operating experience information during the audit to determine if 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 plant operating experience to determine if the applicant 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 effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.13 provides the UFSAR supplement for the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems 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 noted that the applicant committed (Commitment Nos. 3 and 4) to enhance the Inspection of 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 enhance the program to monitor general corrosion on the crane and trolley structural components and the effects of wear on the rails in the rail system and to enhance the program to list additional cranes for monitoring.

The staff determined 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 Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program, the staff determined 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 Nos. 3 and 4 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 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 Compressed Air Monitoring Program

Summary of Technical Information in the Application. LRA Section B.2.1.14 describes the existing Compressed Air Monitoring Program as consistent, with an enhancement, with GALL Report AMP XI.M24, “Compressed Air Monitoring.” The applicant stated that the program manages the aging effects of hardening and loss of strength due to elastomer degradation; loss of material due to crevice, general, galvanic, and pitting corrosion; and reduction of heat transfer due to fouling of the plant compressed air system components. The applicant also stated that the program includes continuous dew point measurements, and sampling for other contaminants in the compressed air system is conducted on an annual basis.

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 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 Report AMP XI.M24. 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 Report AMP XI.M24, with the exception of the “parameters monitored or inspected” program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

GALL Report AMP XI.M24 states that the program’s inspections need to ensure that the intended function of the air system is maintained under the “parameters monitored or inspected” program element description. The applicant’s AMP states that the program specifies inspections to be conducted in accordance with the New Hampshire State inspection requirements; however, the program does not clarify the extent of the inspection or explain whether they are adequate to assure that the intended function of the compressed air system is maintained. By letter dated November 18, 2010, the staff issued RAI B.2.1.14-1 requesting that the applicant provide information on how the in-scope components in the compressed air system will be inspected, consistent with the recommendations defined in GALL Report AMP XI.M24.

In its response dated December 17, 2010, the applicant stated that the program description will explicitly include that visual inspections are to be performed during routine maintenance procedures, and opportunistic inspections will be performed to identify instances of corrosion and the presences of contaminants in the compressed air system, containment compressed air system, and diesel generator compressed air system. Furthermore, the applicant removed the reference to the State of New Hampshire air receiver tank inspection, which is not relied on to meet the recommendations of GALL Report AMP XI.M24. The in-scope components were tabulated in the applicant’s response and are found by staff to be comprehensive.

The staff finds the applicant’s response acceptable because the program description was modified to explicitly state adherence to the GALL Report recommendations. The staff’s concern described in RAI B.2.1.14-1 is resolved.

The staff also reviewed the portions of the “scope of program,” “preventive actions,” “parameters monitored or inspected,” “detection of aging effects," and “acceptance criteria” program elements associated with the enhancement to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement 1. LRA Section B.2.1.14 states an enhancement to the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. The applicant stated that annual air quality testing for particulate content and volatile oil will be conducted to ensure compliance with air quality standards.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M24. The staff noted that the applicant's program appropriately addresses the detection of aging effect by combined air monitoring method so that compressed air quality is confirmed, and corrective actions can be initiated if indicated. The staff finds the applicant's enhancement acceptable because, when conducted in addition to the continuous moisture monitoring of the compressed air system, the annual air quality testing provides adequate monitoring of compressed air quality.

Based on its audit, and review of the applicant's response to RAI B.2.1.14-1, the staff finds that elements one through six of the applicant's Compressed Air Monitoring Program, with an acceptable enhancement, are consistent with the corresponding program elements of GALL Report AMP XI.M24 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.14 summarizes operating experience related to the Compressed Air Monitoring Program. The applicant stated that actions were taken in response to detected rust in an air compressor. The applicant described the detection as being part of an inspection during a repair of the subject compressor. The affected components were replaced, and the engineering analysis led to procedure modifications that isolate susceptible down-stream components from potentially reduced quality compressed air during compressor shutdowns.

The applicant also stated that a minor secondary plant transient occurred due to an air leak in the tubing to a heater drain system level control valve. A material change from copper to stainless steel for smaller instrument lines was conducted to remove the material that was determined to be more susceptible to leakage, and inspections were conducted of critical air-operated valves in high risk systems to evaluate the condition of similar component and material combinations.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 if the applicant 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 effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.14 provides the UFSAR supplement for the Compressed Air Monitoring 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 noted that the applicant committed (Commitment No. 5) to enhance the Compressed Air Monitoring Program prior to entering the period of extended operation. Specifically, the applicant committed to conduct annual air quality testing for particulate content and volatile oil. In addition, the applicant committed (Commitment No. 61) to replace the flexible hoses associated with the diesel generator air compressor on a frequency of every 10 years, beginning within 10 years prior to entering the period of extended operation.

The staff determined 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 Compressed Air Monitoring Program, the staff determined 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. 5 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 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).

3.0.3.2.7 Fire Protection Program

Summary of Technical Information in the Application. LRA Section B.2.1.15 describes the existing Fire Protection Program as consistent, with enhancements, with GALL Report AMP XI.M26, "Fire Protection." The applicant stated that the Fire Protection Program manages aging of penetration seals, fire barrier walls, ceilings, floors, and all fire-rated doors that perform a fire barrier function as well as the aging effects on the intended function of the fuel supply line to the diesel fire pumps. The applicant also stated that the program conducts detailed inspections and tests in accordance with its surveillance test procedures, including regular inspections of fire barriers, penetration seals, and fire-rated doors, and performance tests and flushes on fire pumps. The applicant further stated that it does not use a CO_2 fire suppression system, and the halon fire suppression system is used in a nonsafety-related computer room in the control building; therefore, it is not within the scope of 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 if 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 Report AMP XI.M26. As discussed in the audit report, the staff confirmed that these elements are consistent with the corresponding elements of GALL Report AMP XI.M26.

The staff also reviewed the portions of the "parameters monitored or inspected" and "detection of aging effects" program elements associated with the enhancements to determine if 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.2.1.15 states an enhancement to the "detection of aging effects" program element. The LRA states that the Fire Protection Program implementing documents will be enhanced to include visual inspection of penetration seals by a fire protection qualified inspector.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M26 and noted that the GALL Report recommends that penetration seals be visually inspected by fire protection qualified inspectors. The staff finds the program enhancement acceptable because, when implemented, the program element will be consistent with the recommendations in GALL Report AMP XI.M26.

Enhancement 2. LRA Section B.2.1.15 states an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. The LRA states that the Fire Protection Program implementing documents will be enhanced to include additional age-related degradation inspection criteria such as spalling and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. This enhancement will also include visual inspection of fire-rated exposed barrier walls, floors, and ceilings by a fire protection qualified inspector.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M26 and noted that the GALL Report recommends that fire barrier walls, ceilings, and floors be visually inspected for cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates and that those inspections be performed by a fire protection qualified inspector. The staff finds the program enhancement acceptable because, when implemented, the program element will be consistent with the recommendations in GALL Report AMP XI.M26.

Enhancement 3. LRA Section B.2.1.15 states an enhancement to the "detection of aging effects" program element. The LRA states that the Fire Protection Program implementing documents will be enhanced to include visual inspection of fire-rated doors by a fire protection qualified inspector.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M26 and noted that the GALL Report recommends that fire-rated doors be visually inspected by fire protection qualified inspectors. The staff finds the program enhancement acceptable because, when implemented, the program element will be consistent with the recommendations in GALL Report AMP XI.M26.

Based on its audit, the staff finds that elements one through six of the applicant's Fire Protection Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL Report AMP XI.M26 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.15 summarizes operating experience related to the Fire Protection Program. The applicant stated that leakage was identified on the diesel fire pump casing vent during the surveillance testing in September 2002, and it took appropriate corrective actions and repaired the leak using a preventive maintenance work order. The applicant also stated that it identified two degraded fire barriers in October 2002, and work orders were issued to repair the two barriers. The applicant further stated that it identified a broken fire-door handle in April 2003, and it repaired and retested the door by issuing a work order, which demonstrates that the Fire Protection Program satisfactorily identifies deficiencies.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 plant operating experience information to determine if the applicant 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 effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.15 provides the UFSAR supplement for the Fire Protection 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 noted that the applicant committed (Commitment Nos. 6, 7, and 8) to enhance the Fire Protection Program prior to the period of extended operation. Specifically, the applicant committed to enhance the program to do the following:

- include the performance of visual inspections of penetration seals by a fire protection qualified inspector
- add inspection requirements such as spalling, loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates
- include the performance of visual inspections of fire-rated doors by a fire protection qualified inspector

The staff determined 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 Protection Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the enhancements and their justifications and confirmed that their implementation through Commitment Nos. 6, 7, and 8 prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant 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).

3.0.3.2.8 Fire Water System Program

Summary of Technical Information in the Application. LRA Section B.2.1.16 describes the existing Fire Water System Program as consistent, with enhancements, with GALL Report AMP XI.M27, "Fire Water System." The applicant stated that this program manages the following:

- loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion
- fouling
- reduction of heat transfer due to fouling for fire water system components using detailed inspections in accordance with station surveillance test procedures

The applicant also stated that the SSCs included within the scope of this program include both fire suppression and fire mitigation components. The applicant further stated that the program includes regular inspections, periodic flushing, chemical additions, and performance testing, which are conducted to ensure no corrosion, microbiologically-influenced corrosion, or biofouling has occurred.

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 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 Report AMP XI.M27. 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 Report AMP XI.M27.

The staff also reviewed the portions of the "parameters monitored or inspected" and "detection of aging effects" program elements associated with enhancements to determine if 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.2.1.16 states an enhancement to the "detection of aging effects" program element. The applicant stated that it will enhance its program to include the National Fire Protection Association (NFPA) 25 criteria, which states that "where sprinklers have been in place for 50 years, they will either be replaced or a representative sampling from one or more sample areas will be submitted to a recognized testing laboratory for field service testing." The applicant further stated that sampling will be performed every 10 years after the initial field service testing.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M27. The staff noted that the GALL Report 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 to ensure that signs of degradation, such as corrosion, are detected in a timely manner. The staff finds the applicant's enhancement acceptable because, when implemented, the program element will be consistent with the recommendations in GALL Report AMP XI.M27.

Enhancement 2. LRA Section B.2.1.16 states an enhancement to the "parameters monitored or inspected" program element. The applicant stated that it will enhance its program to include performance of periodic flow testing of the fire water system in accordance with NFPA 25 guidelines.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M27. The staff noted that the GALL Report recommends that periodic flow testing of the fire water system be performed using the guidelines of NFPA 25. The staff finds the applicant's enhancement acceptable because, when implemented, the program element will be consistent with the recommendations in GALL Report AMP XI.M27.

Enhancement 3. LRA Section B.2.1.16 states an enhancement to the "detection of aging effects" program element. The applicant stated that it will enhance its program to include the performance of periodic visual inspections or volumetric inspections of the internal surface of the fire protection system upon each entry to the system for routine or corrective maintenance to evaluate wall thickness and inner diameter of the fire protection piping. The applicant further stated that this inspection will be performed within a 10-year period prior to the period of extended operation.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27. GALL Report AMP XI.M27 recommends that wall thickness evaluations of fire protection piping be performed on system components using non-intrusive techniques 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. LRA Section B.2.1.16 states that "the Fire Water System Program will be enhanced to perform periodic visual inspection or volumetric inspection, as required, of the internal surface of the fire protection system," and that "this inspection will be performed no earlier than 10 years before the period of extended operation." The LRA only indicates when the inspections will not be conducted and does not indicate whether the inspections will be implemented prior to or during the period of extended operation. It is not clear to the staff if the intent of the enhancement is to have the inspections conducted prior to the period of extended operation, as recommended by the GALL Report. By letter dated November 18, 2010, the staff issued RAI B.2.1.16-1 requesting that the applicant confirm whether the inspection activities are planned to start before or during the period of extended operation. If inspections will be not be conducted prior to entering the period of extended operation, the staff asked the applicant to provide technical justification for not conducting the inspections until after entering the period of extended operation.

In its response dated December 17, 2010, the applicant stated that it clarified the inspection commitment requirements in LRA supplement 2, dated November 15, 2010, to state that the inspection will be performed within a 10-year period prior to the period of extended operation. The staff reviewed LRA supplement 2 and noted that the applicant revised LRA Section B.2.1.16 to clarify that the inspections will be performed within 10 years prior to the period of extended operation. The staff finds the applicant's response acceptable because the applicant's inspection commitment is clearly identified as being implemented prior to the period of extended operation, which is consistent with the recommendations in the GALL Report. The staff's concern described in RAI B.2.1.16-1 is resolved.

GALL Report AMP XI.M27 states that, as an alternative to non-intrusive testing, the plant maintenance process may include a visual inspection of the internal surface of the fire protection piping upon each entry to the system for routine or corrective maintenance, as long as it can be demonstrated that inspections are performed on a representative number of locations on a reasonable basis. Neither the applicant's Fire Water System Program description in LRA Section B.2.1.16 nor the program basis documentation provide any indication of how the inspections will be conducted on a representative number of locations on a reasonable basis. By letter dated November 18, 2010, the staff issued RAI B.2.1.16-3 requesting that the applicant explain how the Fire Water System Program inspects a representative number of locations on a reasonable basis, including both opportunistic and directed inspections.

In its response dated December 17, 2010, the applicant revised the LRA to state that the inspections will be documented and trended to determine if a representative number of inspections have been performed prior to the period of extended operation and to conduct focused inspections if a representative number of inspections have not been performed. The staff finds the applicant's response acceptable because the applicant will ensure that a representative number of inspections have been performed prior to entering the period of extend operation, which is consistent with the recommendations in the GALL Report. The staff's concern described in RAI B.2.1.16-3 is resolved.

Based on its audit and review of the applicant's responses to RAIs B.2.1.16-1 and B.2.1.16-3, 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 Report AMP XI.M27 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.16 summarizes operating experience related to the Fire Water System Program. The applicant stated that, in July 2003, a surveillance activity identified a failure to develop required discharge pressure for the fire protection booster pump. The applicant also stated it determined the pump was not sized correctly and replaced the impeller. The applicant further stated that, in July 2004, a maintenance mechanic observed pipe corrosion in the fire pump recirculation header and that a work order was written and the pipe was replaced. The applicant stated that these examples provide evidence of how its routine system maintenance is able to identify deficient conditions and correct them with its Corrective Action Program.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 if the applicant 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 effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.16 provides the UFSAR supplement, as amended, for the Fire Water System 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 noted that it does not indicate that periodic full-flow flush tests and system performance testing are performed or that the visual inspections included in the program will be able to detect wall thickness and the inner diameter of the piping. The licensing basis for the period of extended operation may not be adequate if the applicant does not incorporate this information in its UFSAR supplement. By letter dated November 18, 2010, the staff issued RAI B.2.1.16-2 to request that the applicant justify why it did not indicate that periodic full-flow flush tests and system performance testing are performed and that the visual inspections in the program will be able to detect wall thickness and the inner diameter of the piping.

In its response dated December 17, 2010, the applicant stated that it revised LRA Section A.2.1.16 to state that the Fire Water System Program includes periodic full-flow flush tests and system performance testing per the guidance of NFPA 25. The applicant also revised the UFSAR supplement to state that the program also includes visual inspection of the internal surface of the fire protection piping upon each entry into the system for routine or corrective maintenance that will look for material loss or changes to the inner diameter of the piping. The staff finds the applicant's response acceptable because the applicant revised its UFSAR supplement to include periodic flushing and internal visual inspections, which is consistent with the recommended description for this type of program, as described in SRP-LR Table 3.3-2. The staff's concern described in RAI B.2.1.16-2 is resolved.

The staff noted that the applicant committed (Commitment Nos. 9, 10, and 11) to enhance the Fire Water System Program prior to entering the period of extended operation. Specifically, the applicant committed to enhance the program to do the following:

- include NFPA 25 guidance for where sprinklers have been in place for 50 years, that they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing
- include the performance of periodic flow testing of the fire water system in accordance with the guidance of NFPA 25
- include the performance of periodic visual or volumetric inspections of the internal surface of the fire protection system upon each entry to the system for routine or corrective maintenance
- document and trend performance of the periodic visual or volumetric inspections to determine if a representative number of inspections have been performed prior to the period of extended operation
- conduct focused inspections if a representative number of inspections have not been performed

The staff determined 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 Fire Water System Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff reviewed the enhancements and confirmed that their implementation through Commitment Nos. 9, 10, and 11 prior to the period of extended operation would make the existing AMP consistent with the GALL Report to which it was compared. The staff concludes that the applicant 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).

3.0.3.2.9 Aboveground Steel Tanks Program

Summary of Technical Information in the Application. LRA Section B.2.1.17 describes the existing Aboveground Steel Tanks Program as consistent, with enhancements, with GALL Report AMP XI.M29, "Aboveground Steel Tanks." The applicant stated that the Aboveground Steel Tanks Program manages the aging effects of loss of material due to general, pitting, and crevice corrosion. The applicant also stated that the program includes preventive measures to mitigate corrosion and periodic inspections to validate the effectiveness of the preventive actions. The applicant further stated that the preventive measures include the application of protective coatings on the exterior surfaces of the tanks and caulking and flashing at the auxiliary boiler fuel oil storage and fire protection water storage tank's ground interface. The applicant stated that the two diesel fire pump fuel oil tanks are raised on steel supports clear of their concrete foundations. The applicant also stated that ultrasonic thickness measurements of the tank bottom surface will be performed from inside the tank to detect any exterior material degradation.

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 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 Report AMP XI.M29. 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 Report AMP XI.M29, with the exception of the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. For these elements, the staff determined the need for additional clarification, which resulted in the issuance of RAIs.

GALL Report AMP XI.M29 recommends that the program use periodic system walkdowns to monitor degradation of the protective paint or coating under the "parameters monitored or inspected" program element description. However, LRA Section B.2.1.17 states that visual inspection of the external surface of the protective coatings on exterior surface of the in-scope tanks will be conducted in accordance with its Structures Monitoring Program. The staff noted that this program does not state that coating inspections of aboveground steel tanks is within its scope. By letter dated November 18, 2010, the staff issued RAI B.2.1.17-1 requesting that the applicant confirm that its Structures Monitoring Program includes coating inspection of aboveground steel tanks.

In its response dated December 17, 2010, the applicant stated that its Structures Monitoring Program is revised to include an external inspection of the aboveground steel tanks to inspect the paint or coating for cracking, flaking, or peeling. The staff finds the applicant's response acceptable because the applicant's Structures Monitoring Program includes coating inspection of the aboveground steel tanks to monitor degradation of the coatings. The staff's concern described in RAI B.2.1.17-1 is resolved.

GALL Report AMP XI.M29 recommends that periodic system walkdowns be conducted to confirm that the sealant and caulking at the interface edge between the tank and concrete are intact under the "parameters monitored or inspected" and "detection of aging effects" program element descriptions. The staff noted that LRA Section B.2.1.17 states that visual inspection will be performed to detect drying, cracking, or missing sealant and caulking applied along the tank and ground interface. The staff believes that to detect hardening and loss of strength in elastomeric materials it is necessary to supplement the visual inspection with physical manipulation of the sealant and caulking. By letter dated November 18, 2010, the staff issued RAI B.2.1.17-3 requesting that the applicant confirm that its Aboveground Steel Tanks Program includes manual manipulation of elastomeric sealant and caulking material to detect hardening and loss of strength.

In its response dated December 17, 2010, the applicant stated that its Aboveground Steel Tanks Program is revised to include a visual and tactile examination of the sealant and caulking on the exterior surfaces of the aboveground steel tanks. The applicant also stated that the examination consists of pressing on the sealant or caulking to detect a reduction in the resiliency and pliability. The staff finds the applicant's response acceptable because the applicant's Aboveground Steel Tanks Program includes visual inspections and physical manipulation, which are capable of detecting degradation of the sealant and caulking. The staff's concern described in RAI B.2.1.17-3 is resolved.

GALL Report AMP XI.M29 recommends that "[a]ny degradation of paint, coating, sealant, and caulking is reported and will require further evaluation. Degradation consists of cracking, flaking, or peeling of paint or coatings, and drying, cracking or missing sealant and caulking" under the "acceptance criteria" program element description. The staff noted that LRA Section B.2.1.17 states an enhancement to the Aboveground Steel Tanks Program by adding paint flaking and drying, cracking, or missing sealant and caulking as examples of minor structural deficiencies. The staff does not understand the context of the term "minor structural deficiencies" and how it relates to the need for further evaluation of the condition. By letter dated November 18, 2010, the staff issued RAI B.2.1.17-4 requesting that the applicant clarify whether the term "minor structural deficiency" implies that no further evaluation of the degraded condition will occur, and, if no further evaluation will occur, the staff asked the applicant to justify this as an exception to GALL Report AMP XI.M29.

In its response dated December 17, 2010, the applicant stated that the term "minor structural deficiency" in LRA Section B.2.1.17 is revised to "degradation." The staff finds the applicant's response acceptable because the applicant has changed the term "minor structural deficiency" to "degradation" in its Aboveground Steel Tanks Program; therefore, all degraded conditions will be entered into its Corrective Action Program. The staff's concern described in RAI B.2.1.17-4 is resolved.

GALL Report AMP XI.M29 recommends that, "[t]he effects of corrosion of the underground external surface are detectable by thickness measurement of the tank bottom and are monitored and trended if significant material loss is detected" under the "monitoring and trending" program element description. The staff noted that LRA Section B.2.1.17 states that, for the two fire protection water storage tanks, the program will be enhanced to include the performance of a UT examination of the internal tank bottom surface within 10 years prior to the period of extended operation. The staff is not clear whether the UT examination is a one-time or periodic inspection. By letter dated November 18, 2010, the staff issued RAI B.2.1.17-5 requesting that the applicant clarify whether the UT examination specified in LRA Section B.2.1.17 is a one-time measurement or periodic inspection. If it is a one-time ultrasonic inspection, the staff asked the applicant to justify how the one-time measurement can be used for monitoring and trending of aging effects.

In its response dated December 17, 2010, the applicant stated that a one-time ultrasonic thickness measurement of the tank bottoms will be performed within 10 years prior to the period of extended operation (Commitment No. 13). The applicant also stated that any thickness measurements indicating less than nominal thickness will require a condition report to ensure than an engineered evaluation is performed and any necessary monitoring and trending is identified. The staff finds the applicant’s response acceptable because the applicant will perform an engineering evaluation of any thickness measurements less than nominal thickness and the evaluation will identify any required monitoring and trending. The staff’s concern described in RAI B.2.1.17-5 is resolved.

The staff also reviewed the portions of the “scope of program,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements associated with enhancements to determine if 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.2.1.17 states an enhancement to the “scope of program,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements. The LRA, as updated by the applicant's response to RAI B.2.1.17-4 dated December 17, 2010, states that the Aboveground Steel Tanks Program implementing procedures will be enhanced to do the following:

- include the fire protection fuel oil tanks, auxiliary boiler fuel oil storage tank, and fire protection water storage tanks as part of the scope of tanks
- add paint flaking and drying, cracking, or missing sealant and caulking as examples of degradation
- add a requirement that discrepant conditions be reported through the applicant’s Corrective Action Program

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M29. The staff noted that the applicant’s program appropriately identifies specific components, aging effects, and the need for corrective actions to ensure that aging effects are managed. The staff’s evaluation of RAI B.2.1.17-4 related to the applicant changing the term “minor structural deficiency” to “degradation” in its Aboveground Steel Tanks Program is documented above. 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 elements consistent with the recommendations in GALL Report AMP XI.M29.

Enhancement 2. LRA Section B.2.1.17 states an enhancement to the “scope of program,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements. The LRA states that the Aboveground Steel Tanks Program implementing procedures will be enhanced to include the performance of an ultrasonic examination and evaluation of the internal bottom surface of the two fire protection water storage tanks within 10 years prior to the period of extended operation.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M29 and noted that the applicant’s program appropriately identifies thickness measurements of the tank bottoms and associated evaluation to detect degradation of the two fire protection water storage tanks. The staff’s evaluation of RAI B.2.1.17-5 related to whether the UT examination is a one-time measurement or periodic inspection is documented above. 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 elements consistent with the recommendations in GALL Report AMP XI.M29.

Based on its audit and review of the applicant's response to RAIs B.2.1.17-1, B.2.1.17-3, B.2.1.17-4, and B.2.1.17-5, 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 Report AMP XI.M29 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.17 summarizes operating experience related to the Aboveground Steel Tanks Program. The applicant stated that degradation of coatings was reported on the fire protection fuel oil tanks in 1999. As a result, the applicant stated that the tanks were surface prepped and re-coated. The applicant also stated that, in response to a condition of chipped paint and rusting metal surface around the lower manways of the fire protection water storage tanks in 2001, it took appropriate corrective actions to have the tanks surface prepped and re-coated to maintain the structural integrity of the tanks.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 plant operating experience information to determine if the applicant 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 effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.17 provides the UFSAR supplement for the Aboveground Steel Tanks 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 Tables 3.3-2 and 3.4-2.

The staff reviewed the applicant's UFSAR supplement and found that it does not indicate that visual inspections of sealant and caulking inspections are included in the program. The example description for this program in SRP-LR Tables 3.3-2 and 3.4-2 include specific mention of this inspection. The licensing basis for the period of extended operation may not be adequate if the applicant does not incorporate this information in its UFSAR supplement. By letter dated November 18, 2010, the staff issued RAI B.2.1.17-2 requesting that the applicant justify why visual inspections of sealant and caulking are not included in the UFSAR supplement as part of the scope of the program.

In its response dated December 17, 2010, the applicant stated that it revised its UFSAR supplement, Section A.2.1.17, to include visual inspections of the sealant and caulking on the exterior surfaces of the aboveground steel tanks. The staff finds the applicant's response acceptable because the applicant revised its Aboveground Steel Tanks Program UFSAR supplement to include visual inspections of the sealant and caulking in the program; therefore, the licensing basis is now adequate. The staff's concern described in RAI B.2.1.17-2 is resolved.

The staff noted that the applicant committed (Commitment No. 12) to enhance the Aboveground Steel Tanks Program to include in-scope components and aging effects prior to the period of extended operation.

The staff also noted that the applicant committed (Commitment No. 13) to enhance the Aboveground Steel Tanks Program prior to the period of extended operation. Specifically, the applicant committed to include an ultrasonic inspection and evaluation of the internal bottom surface of the two fire protection water storage tanks.

The staff determined 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 Aboveground Steel Tanks Program, the staff determined 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 Nos. 12 and 13 prior to the period of extended operation would make the AMP consistent with the GALL Report AMP to which it is compared. The staff concludes that the applicant 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 Program

Summary of Technical Information in the Application. LRA Section B.2.1.18 describes the existing Fuel Oil Chemistry Program as consistent, with exceptions and enhancements, with GALL Report AMP XI.M30, "Fuel Oil Chemistry." The applicant stated that the existing Fuel Oil Chemistry Program manages the aging effects of loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion as well as loss of material due to fouling in the diesel fuel oil systems for the emergency diesel generators, diesel engine driven fire protection system pumps, and the auxiliary boiler fuel oil system. The program manages the aging effects through monitoring and maintenance of diesel fuel oil quality. The applicant further states that the program manages these aging effects for the diesel generator fuel oil storage tanks, the diesel generator fuel oil day tanks, the diesel fire pump fuel oil day tanks, the auxiliary boiler fuel oil storage tank and the associated piping, tubing, and valves. The program manages such aging by maintaining fuel oil chemistry, removing water, and cleaning and inspecting the 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 if they are bounded by the conditions for which the GALL Report was evaluated.

The staff also reviewed the portions of the "scope of 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 if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exception and enhancements follows.

Exception 1. LRA Section B.2.1.18 states an exception to the "preventive actions" program element. The GALL Report recommends maintaining the quality of fuel oil by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. Alternatively, the applicant stated that plant operating experience has shown that monthly testing for and removal of water along with the purchase of quality fuel oil negates the need for stabilizers or corrosion inhibitors. All new fuel shipments are sampled from the delivery tanker to verify they meet the applicable American Society for Testing and Materials (ASTM) standards prior to being offloaded into the associated storage tank. The applicant stated further that the fuel oil is used and topped off often enough to negate the need for stabilizers or corrosion inhibitors.

The staff reviewed this exception with the GALL Report and noted that the applicant took exception because stabilizers or corrosion inhibitors are not used in the diesel fuel oil. Additionally, biocide is added only to the diesel fuel oil storage tanks. The staff finds this exception acceptable and this program element consistent to the one described in the GALL because the applicant manages the aging effects of the components by maintaining fuel oil chemistry through monthly sampling, removal of any accumulated water if found, and cleaning and inspecting the associated fuel oil tanks. The applicant also ensures the quality of the fuel oil purchased by sampling each fuel oil shipment prior to being offloaded. These actions demonstrate the intent to minimize biological activity, prevent biological breakdown of the diesel fuel, and mitigate corrosion, as recommended in the GALL Report AMP XI.M30.

Exception 2. LRA Section B.2.1.18 states an exception to the “parameters monitored or inspected” and “acceptance criteria” program elements. The GALL Report recommends using the modified ASTM Standard D2276, Method A, for determination of particulates. The modification consists of using a filter with a pore size of 3.0 μm instead of 0.8 μm to filter the particulates from the fuel oil sample for subsequent analysis. Alternatively, the applicant stated that the non-modified ASTM Standard D2276, which uses the 0.8 μm filter, is used to sample particulates. The applicant further states that the small pore size of the 0.8 μm filter retains more particulates and, therefore, is conservative as the analysis for particulates is based on the total weight of particulates captured.

The staff reviewed this exception with the GALL Report and noted that the applicant took exception because the non-modified ASTM Standard D2276 is used for the analysis of particulates in fuel oil. The staff finds this exception acceptable because the analysis for particulates is based on the total weight of particulates captured; therefore, using a smaller pore sized filter will make the applicant’s analysis of particulates more conservative than what is recommended in the GALL Report AMP XI.M30.

Exception 3. LRA Section B.2.1.18 states an exception to the “parameters monitored or inspected” and “acceptance criteria” program elements. The GALL Report recommends using the ASTM Standards D1796 and D2709 for determination of water and sediment contamination in diesel fuel. Alternatively, the applicant stated that ASTM Standard D4176 and D2709 would be used for determination of water and sediment contamination in diesel fuel. The applicant further stated that ASTM Standard D4176 is used to perform a clear and bright test of light fuel oil and can be performed in the field as well as in the lab and is an easy first screening to determine the quality of fuel oil. The applicant stated that using one lab test to analyze for water and particulate coupled with the field clear and bright test provides an acceptable approach for detecting water and particulates in the delivered diesel generator fuel oil.

The staff noted that the applicant took exception to the GALL Report in that the applicant incorporates ASTM Standard D4176 versus D1796 for the use in detecting water and particulates in fuel oil. The staff finds this exception acceptable because the detection limit of ASTM Standard D4176 for free water and particulate contamination, with an experienced operator, is approximately 40 ppm and is not dependent on ambient temperature above the cloud point of the fuel. The detection limit for ASTM Standard D2709 is 50 ppm at 21-32 °Celsius (C). The staff finds the use of ASTM Standard D4176 an acceptable substitute to ASTM Standard D1796 because it allows the applicant to have an immediate indication of any contamination in a fuel delivery prior to allowing the fuel to reach the fuel storage tanks. The use of ASTM Standard D4176 along with ASTM Standard D2709 allows two separate checks of the fuel oil using two different analyses with similar detection limits. The staff finds the use of these two standards consistent with the GALL Report AMP XI.M30.

Exception 4. LRA Section B.2.1.18 states an exception to the "parameters monitored or inspected" and "acceptance criteria" program elements. The GALL Report recommends using ASTM Standard D2276-00 for determining particulate in diesel fuel oil. Alternatively, the applicant uses ASTM Standard D2276-06. The applicant stated that the basic methodology between the two revisions of the standards had not changed, and the 2006 version of the standard had updated figures and notes from previous revisions that were incorporated into the procedural steps. The applicant further stated that the figure and methodology for taking aviation jet fuel samples had changed but is not used by the applicant.

The staff noted that the applicant took exception to the GALL Report in that the applicant uses ASTM Standard D2276-06 versus ASTM Standard D2276-00. The staff reviewed both revisions of the standard and finds that this exception is acceptable because the methodology for determining particulate in diesel fuel oil has not changed between the two revisions. The applicant's use of ASTM Standard D2276-06 is consistent with the GALL Report AMP XI.M30.

Enhancement 1. LRA Section B.2.1.18 states an enhancement to the "scope of program," "preventive actions," "parameters monitored or inspected," and "monitoring and trending" program elements. This enhancement expands on the existing program elements by adding the requirement to sample and analyze new fuel deliveries, including testing for biodiesel, prior to offloading to the auxiliary boiler fuel oil storage tank. Additionally, the enhancement will require that the auxiliary boiler fuel oil storage tank be sampled periodically.

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 of GALL Report AMP XI.M30.

Enhancement 2. LRA Section B.2.1.18 states an enhancement to the "preventive actions" program element. This enhancement expands on the existing program element by adding the requirement to check for the presence of water in the auxiliary boiler fuel oil storage tank at least once per quarter to remove water as necessary.

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 of GALL Report AMP XI.M30.

Enhancement 3. LRA Section B.2.1.18 states an enhancement to the "scope of program," "preventive actions," "parameters monitored or inspected," and "monitoring and trending" program elements. This enhancement expands on the existing program elements by adding the requirement to drain, clean, and inspect the diesel fire pump fuel oil day tanks on a frequency of at least once every 10 years.

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 of GALL Report AMP XI.M30.

Enhancement 4. LRA Section B.2.1.18 states an enhancement to the "preventive actions" and "detection of aging effects" program elements. This enhancement expands on the existing program elements by adding the requirement to perform an ultrasonic thickness measurement of the tank bottom during the 10-year draining, cleaning, and inspection of the diesel generator fuel oil storage tanks, diesel generator fuel oil day tanks, diesel fire pump fuel oil day tanks, and auxiliary boiler fuel oil storage tank.

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 of GALL Report AMP XI.M30.

Enhancement 5. LRA Section B.2.1.18 states an enhancement to the "parameters monitored or inspected" and "acceptance criteria" program elements. By letter dated December 14, 2010, the staff issued RAI B.2.1.18-2 requesting that the applicant clarify the revisions of ASTM standards used for the program. In its response dated January 13, 2011, the applicant amended this enhancement by updating the Technical Requirement Program 5.1 (Diesel Fuel Oil Testing Program) to use ASTM Standards D2709-96 and D4057-95, as required by GALL Report AMP XI.M30, Revision 1, prior to the period of extended operation. The current revision of the applicant's Technical Requirement Program 5.1 uses ASTM Standards D2709-82 and D4057-81.

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 of GALL Report AMP XI.M30.

Based on its audit and review of the applicant's response to RAI B.2.1.18-2, 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 Report AMP XI.M30 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.18 summarizes operating experience related to the Fuel Oil Chemistry Program. The staff reviewed this information and interviewed the applicant's technical personnel to confirm that the applicable aging effects and industry and plant-specific operating experience have been reviewed by the applicant and are evaluated in the GALL Report. During the audit, the staff independently confirmed that the applicant adequately incorporated and evaluated operating experience related to this program.

The staff reviewed the following information regarding operating experience:

(1) In November 2000, a trend of increasing particulates was identified in diesel generator fuel oil storage tank, 1-DG-TK-26B. Test results from two samples showed particulate matter at 11.8 mg/L and 11.2 mg/L which exceeded the limit of 10 mg/L. As a corrective action, both diesel generator fuel oil storage tanks (1-DG-TK-26A and 26B) were filtered to a particulate matter of less than <0.3 mg/L, a condition report was written along with a work order to correct the issue, and a cause analysis was performed. The cause analysis determined that a combination of factors were potential contributors to the high particulate count. Corrective actions included cleaning of the diesel generator day tanks, more frequent replacement of the associated fuel oil filters (every 6 months), reviewing

the lube oil-fuel oil interfaces to rule out lube oil contamination of the fuel as a major contributor and planning for future potential particulate clean-up activities. The plant did not experience a loss of intended function of the diesel generator due to the high particulate count.

(2) A review of work orders associated with the cleaning and inspection of diesel generator fuel oil storage tanks and day tanks and the fire pump fuel oil day tanks indicate no degradation of the tanks. The "A" diesel generator fuel oil storage tank was drained and the bottom UT inspected in 1994 and 2003. The "B" diesel generator fuel oil storage tank was drained and the bottom UT examination was performed on the tank bottom in 1994 and 2005. The "A" diesel generator fuel oil day tank was drained, cleaned and inspected in 2003. The "B" diesel generator fuel oil day tank was drained, cleaned and inspected in 2005.

(3) In June 2001, an inspection of the internal bottom surface of the auxiliary boiler fuel oil storage tank (AB-TK-29) was performed by certified personnel under a work order and in accordance with a Seabrook Station specification for cleaning, inspection and repair of the bulk fuel oil storage tank. Inspection results were captured in a technical inspection and engineering analysis report. The report indicated minimal thickness loss on the nominal $^{1}/_{4}$" thick floor after 26 years. No degradation of the tank floor was characterized as major.

(4) A review of Seabrook Station condition reports identified instances when the new fuel oil deliveries were rejected due to the presence of water. In December of 2004, a fuel shipment for the emergency diesel generators did not meet the acceptance criteria of the clear and bright test. Samples were analyzed for water, particulate, and haze. Visible water droplets could be seen at the bottom of the clear and bright bottle.

A second sample was taken, and it also had visible water droplets in the sample bottle and therefore, the tanker fuel oil shipment was rejected. In September of 2005, a fuel shipment for the emergency diesel generators did not meet the acceptance criteria for flashpoint. The flashpoint reading of 117°F was below the minimum requirement of 125°F and therefore, the tanker fuel oil shipment was rejected. In these instances, corrective actions were taken to correct the out of specification condition prior to offloading the fuel oil into the diesel generator fuel oil storage tank.

(5) Although not discussed in GALL Report AMP XI.M30, the NRC had recently issued Information Notice 2009-02, “Biodiesel in Fuel Oil Could Adversely Impact Diesel Engine Performance.” This document indicates that No. 2 diesel fuel could contain up to a 5 percent bio-diesel fuel (B5) blend without labeling the blend in accordance with ASTM D 975-08a, “Standard Specification for Diesel Fuel Oils.” Bio-diesel B5 blend: (a) can have a cleansing effect that can increase sediment that could plug filters, (b) could form “dirty water” which leads to algae growth, (c) is biodegradable such that long term storage is not recommended and (d) can be more susceptible to gel creation in the presence of brass, bronze and copper fittings, piping, and tanks. These effects could lead to plant-specific operating experience outside the bounds of industry operating experience. Existing Seabrook Station plant procedures test for bio-diesel prior to offload of fuel oil to the diesel generator fuel oil storage tanks and fire pump fuel oil day tanks. Acceptance criteria for bio-diesel is <2 percent (non-detectable).

The staff reviewed the operating experience information, in the application and during the audit, to determine if 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 if the applicant 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 the 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; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.18 provides the UFSAR supplement for the Fuel Oil Chemistry Program. The staff reviewed the 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 found that the description of the Fuel Oil Chemistry Program, as described in LRA Section A.2.1.18, does not indicate which ASTM standards the program implements but simply states the program will use the applicable ASTM standards. The example description for this program in SRP-LR Table 3.3-2 includes specific mention of ASTM Standards D1796, D4057, D2709, and D2276. The licensing basis for the period of extended operation may not be adequate if the applicant does not incorporate this information in its UFSAR supplement.

By letter dated December 14, 2010, the staff issued RAI B.2.1.18-1 requesting that the applicant justify why it did not include the referenced ASTM standards. In its response dated January 13, 2011, the applicant amended the UFSAR supplement in LRA Section A.2.1.18. The amended UFSAR supplement states the following:

> New fuel oil is sampled and verified to meet the requirements of applicable American Society for Testing and Materials (ASTM) standards D4057 and D2709 prior to offloading to the storage tanks. Stored fuel oil is sampled and verified to meet the requirements of ASTM D2276 or ASTM D4057, and ASTM D2709. The program monitors fuel oil quality and levels of water in the fuel oil which may cause the loss of material of the tank internal surfaces. The program monitors water and sediment contamination in diesel fuel.

With this amendment, the staff finds the UFSAR supplement for the Fuel Oil Chemistry Program acceptable because it is consistent with the corresponding program description in SRP-LR Table 3.3-2. The staff's concern described in RAI B.2.1.18-1 is resolved.

The staff also noted that the applicant committed (Commitment Nos. 14, 15, 16, 17, and 58) to enhance the Fuel Oil Chemistry Program prior to entering the period of extended operation. Specifically, the applicant committed to do the following:

(1) Enhance program to add requirements to 1) sample and analyze new fuel deliveries for biodiesel prior to offloading to the auxiliary boiler fuel oil storage tank and 2) periodically sample stored fuel in the auxiliary boiler fuel oil storage tank.

(2) Enhance the program to add requirements to check for the presence of water in the auxiliary boiler fuel oil storage tank at least once per quarter and to remove water as necessary.

(3) Enhance the program to require draining, cleaning and inspection of the diesel fire pump fuel oil day tanks on a frequency of at least once every ten years.

(4) Enhance the program to require ultrasonic thickness measurement of the tank bottom during the 10-year draining, cleaning and inspection of the diesel generator fuel oil storage tanks, diesel generator fuel oil day tanks, diesel fire pump fuel oil day tanks and auxiliary boiler fuel oil storage tank.

(5) Update Technical Requirement Program 5.1, (Diesel Fuel Oil Testing Program) ASTM standards to ASTM D2709-96 and ASTM D4057-95 required by the GALL XI.M30 Rev 1.

The staff determined 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 Fuel Oil Chemistry Program, the staff determined 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 determined 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 Nos. 14, 15, 16, 17, and 58, 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 Program

Summary of Technical Information in the Application. LRA Section B.2.1.19 describes the existing Reactor Vessel Surveillance Program as consistent, with enhancements, with GALL Report AMP XI.M31," Reactor Vessel Surveillance." The applicant included the following four enhancements:

(1) The program will specify that all pulled and tested capsules, unless discarded before August 31, 2000, are placed in storage (Criteria 1).

(2) The program will specify that if plant operations exceed the bounds defined by the RV Surveillance Program, such as operating at a lower cold leg temperature or higher fluence, the impact of plant operation changes on the extent of reactor vessel embrittlement will be evaluated, and the NRC will be notified (Criteria 1).

(3) The program will ensure the appropriate withdrawal schedule for capsules remaining in the vessel such that one capsule will be withdrawn at an outage in which the capsule receives a neutron fluence that meets the regulatory requirements and that bounds the 60-year fluence. The remaining capsule(s) will be removed from the vessel unless determined to provide meaningful metallurgical data (Criteria 5).

(4) The program will ensure that any capsule removed without testing will be stored in a manner that maintains it in a condition, which would permit its future use, including during the period of extended operation (Criteria 5).

With these enhancements, the applicant stated that the existing Reactor Vessel Surveillance Program will provide reasonable assurance that loss of fracture toughness due to neutron irradiation embrittlement will be adequately managed so that the intended functions of components within the scope of license renewal will be maintained consistent with the CLB during the period of extended operation.

Staff Evaluation. Appendix H of 10 CFR Part 50 specifies surveillance program criteria for 40 years of operation. GALL Report AMP XI.M31 specifies additional criteria for 60 years of operation. The staff determined that compliance with 10 CFR Part 50, Appendix H, criteria for capsule design, location, specimens, test procedures, and reporting remains appropriate for this Seabrook AMP because these items, which satisfy 10 CFR Part 50, Appendix H, will stay the same throughout the period of extended operation.

The 10 CFR Part 50, Appendix H, capsule withdrawal schedule during the period of extended operation is addressed in accordance with the Section XI.M31 consideration of eight criteria for an acceptable reactor pressure vessel (RPV) surveillance program for 60 years of operation.

The staff reviewed LRA B.2.1.19 with its four enhancements and the associated justifications to determine if the AMP is adequate to manage the aging effects for which it is credited. The enhancements address three of the eight AMP acceptance criteria (Criteria 3, 4, and 6) in GALL Report AMP XI.M31.

Enhancement 1. LRA Section B.2.1.19 states an enhancement to the program related to Criterion 4 in the GALL Report AMP XI.M31. The enhancement describes the storage requirements and the need to retain future pulled capsules. This enhancement meets the fourth criterion of GALL Report AMP XI.M31 and will keep used surveillance specimens for future use.

Enhancement 2. LRA Section B.2.1.19 states an enhancement to the program related to Criterion 3 in the GALL Report AMP XI.M31. The enhancement limits the RPV cold leg temperature and neutron fluence projections. This enhancement meets the third criterion of GALL Report AMP XI.M31 and will increase the quality of the surveillance data.

Enhancement 3. LRA Section B.2.1.19 states an enhancement to the program related to Criterion 6 in the GALL Report AMP XI.M31. The enhancement specifies capsule withdrawal schedule, meeting the sixth criterion of GALL Report AMP XI.M31 because the surveillance program consists of capsules with a projected fluence exceeding the 60-year fluence at the end of 40 years. The Seabrook Reactor Vessel Surveillance Program will withdraw one of the remaining capsules at an outage in which the capsule receives a neutron fluence that meets the schedule requirements of 10 CFR Part 50 Appendix H and ASTM E185-82 and that bounds the 60-year fluence and test that capsule in accordance with the requirements of ASTM E185-82.

Enhancement 4. LRA Section B.2.1.19 states an enhancement to the program related to Criterion 6 in the GALL Report AMP XI.M31. The enhancement incorporates the requirements for withdrawing the remaining capsules and placing them in storage when the monitor capsule is withdrawn during the period of extended operation. This enhancement also meets the second part of the sixth criterion of GALL Report AMP XI.M31 and makes reinstituting an RPV Surveillance Program achievable under conditions such as change of the exposure conditions of the RPV.

The staff's review of this Seabrook AMP against the remaining four criteria is discussed below.

Criteria 1 and 2 of GALL Report AMP XI.M31 regard evaluation of the 60-year upper-shelf energy (USE) and pressure-temperature (P-T) limits, using RG 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials.” LRA Section B.2.1.19 states that Seabrook has documented the extent of embrittlement for USE and P-T limits for 60 years (55 effective full power years (EFPYs)), in accordance with RG 1.99, Revision 2, using both the chemistry tables and existing surveillance data as applicable. LRA Section B.2.1.19 further states that surveillance capsule data from all capsules withdrawn to date was used to obtain the relationship between the mean value of nil-ductility reference temperature (RT_{NDT}) change due to fluence as discussed in Position 2.1 of RG 1.99, Revision 2. Since the Seabrook AMP evaluates the 60-year USE and P-T limits fully in accordance with RG 1.99,Revision 2, including the limitations specified in Criterion 2, Criteria 1 and 2 are satisfied.

Criterion 5 (for plants with a surveillance program that consists of capsules with a projected fluence of less than the 60-year fluence at the end of 40 years) and Criterion 7 (for plants not having surveillance capsules) do not apply to the Seabrook AMP.

Criterion 8 asks for justification for not including nozzle specimens in the surveillance program. The applicant did not address this issue explicitly in LRA Section B.2.1.19. However, this item was addressed indirectly in Section 4.2.3 of the LRA in which the applicant does not include nozzle materials that will not exceed the surface fluence value of 1.0×10^{17} neutrons per square centimeter (n/cm^2)(E > 1.0 MeV) at 55 effective full power years. The staff finds Criterion 8 is satisfied. The staff's evaluation of the RPV beltline and extended beltline materials for the period of extended operation meeting the requirements of 10 CFR 54.21(c)(1)(ii), in which the analyses have been projected for 60 years of operation are documented in SER Section 4.2.3.

Based on its audit, the staff finds that the eight criteria of the applicant’s Reactor Vessel Surveillance Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL Report AMP XI.M31 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.19 summarizes operating experience related to the Reactor Vessel Surveillance Program. The applicant cited evaluation results of three surveillance capsules withdrawn from 1991–2005 to conclude that the materials met the requirements for continued safe operation. The cited evaluation results provide evidence that the existing Reactor Vessel Surveillance Program will be capable of monitoring the aging effects associated with the loss of fracture toughness due to neutron irradiation embrittlement of the RPV beltline materials. The staff concurred with the applicant’s conclusion, as supported by the staff’s approval of the current pressurized thermal shock evaluation and P-T limits, using information from all surveillance data in accordance with RG 1.99, Revision 2.

Furthermore, the applicant demonstrated that the plant responded to industry operating experience related to damage that another similar facility found in the lower internals support flange and the surveillance capsule access plug in the lower internals flange. The applicant conducted an underwater-camera visual inspection to document that similar damage had not occurred at Seabrook.

The staff reviewed operating experience information in the application to determine if the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. 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 the 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; therefore, the staff finds it acceptable.

UFSAR Supplement. The applicant provided its UFSAR supplement for the Reactor Vessel Surveillance Program in LRA Section A.2.1.19.

The staff also noted that the applicant committed (Commitment Nos. 18-21) to implement the existing Reactor Vessel Surveillance Program with the enhancements listed below prior to entering the period of extended operation:

- The applicant will specify that all pulled and tested capsules, unless discarded before August 31, 2000, are placed in storage.
- The applicant will specify that if plant operations exceed the limitations or bounds defined by the Reactor Vessel Surveillance Program, such as operating at a lower cold leg temperature or higher fluence, the impact of plant operation changes on the extent of reactor vessel embrittlement will be evaluated, and the NRC will be notified.
- The applicant will ensure the appropriate withdrawal schedule for capsules remaining in the vessel, such that one capsule will be withdrawn at an outage in which the capsule receives a neutron fluence that meets the schedule requirements of 10 CFR 50, Appendix H, and ASTM E185-82 and that bounds the 60-year fluence. The remaining capsules(s) will be removed from the vessel unless determined to provide meaningful metallurgical data.
- The applicant will ensure that any capsule removed, without the intent to test it, is stored in a manner that maintains it in a condition that would permit its future use, including during the period of extended operation.

The staff determined 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 Reactor Vessel Surveillance Program, the staff determined 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 prior to the period of extended operation supports the requirements of the AMP. The staff concludes that the applicant 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).

3.0.3.2.12 Selective Leaching of Materials Program

Summary of Technical Information in the Application. LRA Section B.2.1.21 describes the new Selective Leaching of Materials Program as consistent, with an exception, with GALL Report AMP XI.M33, "Selective Leaching of Materials." The applicant stated that the Selective Leaching of Materials Program will manage the aging effect of loss of material due to selective leaching in gray cast iron, copper alloys greater than 8 percent aluminum (e.g., aluminum-bronze) and copper alloy (greater than 15 percent zinc) exposed to raw water, brackish water, treated water (including closed-cycle cooling), or groundwater.

The applicant also stated that the program will use one-time visual inspections and mechanical test techniques such as chipping, scraping, or hardness testing to determine if selective leaching is occurring. The applicant further stated that inspections will include a representative sample of the most susceptible locations selected from each material and environment combination with a sample size of 20 percent, not to exceed a sample size of 25 components. The applicant stated that if evidence of selective leaching is discovered, it will perform an engineering evaluation to determine acceptability of the affected components for continued service and implement an expansion of the inspection sample size and location.

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 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 Report AMP XI.M33. 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 Report AMP XI.M33, with the exception of the "parameters monitored or inspected" and "detection of aging effects" program elements. For these elements, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

GALL Report AMP XI.M33 recommends a possible expansion of the inspection sample size and location if selective leaching is detected under the "parameters monitored or inspected" program element description. The "detection of aging effects" program element description also recommends the initiation of an engineering evaluation to determine the acceptability of the affected components if selective leaching has occurred. LRA Section B.2.1.21 states that Seabrook has experienced instances of de-aluminization of aluminum bronze components having an internal environment of raw seawater. Given that selective leaching of aluminum-bronze components has occurred, it is unclear how an expansion of the inspection sample sizes and locations are being implemented. By letter dated November 18, 2010, the staff issued RAI B.2.1.21-1 requesting that the applicant clarify if the Selective Leaching of Materials Program has implemented an expansion of the inspection sample size and location for aluminum bronze components given that selective leaching has occurred. The staff asked the applicant to describe the methodology and criteria for selecting a representative sample population that envelopes all plant systems and working conditions at locations most susceptible to selective leaching. If the expansion has not been implemented, the applicant was asked to describe any planned inspection and associated activities ahead and to justify the methodology, sample size, and location used for selecting components with different material and environment combinations for selective leaching inspections.

In its response dated December 17, 2010, the applicant stated that the Selective Leaching of Materials Program had been revised to expand the inspection sample size and location for aluminum-bronze components upon discovery of unacceptable inspection results. The revised program includes a one-time inspection of selected components where selective leaching has not been previously identified and periodic inspections of selected components where selective leaching has been identified. The applicant further stated that both visual and mechanical examination techniques (Brinell hardness testing or other mechanical examination techniques such as destructive testing, when appropriate, scraping, chipping, or other types of hardness testing) would be used to determine if selective leaching is occurring. The applicant further stated that an initial inspection of the aluminum bronze components of a sample size of 20 percent of the population with a maximum of 25 locations would be performed within 5 years prior to entering the period of extended operation. The selection of locations will consider time in service, severity of operating conditions, lowest design margin, and distribution of susceptible components across systems within similar material and environment combinations. The applicant further stated that followup of unacceptable inspection findings would include an evaluation using the Corrective Action Program and a possible expansion of the inspection size and location. The applicant also stated that it has previously identified selective leaching in aluminum bronze components in raw water; therefore, all in-scope aluminum bronze components in a raw water environment will be grouped separately from other copper-alloy (greater than 15 percent zinc) components and be inspected periodically.

The staff finds the applicant’s response acceptable because the applicant’s revised Selective Leaching of Materials Program is consistent with the GALL Report AMP XI.M33 recommendation of performing a one-time visual inspection of selected components susceptible to selective leaching, coupled with either hardness measurements or mechanical examination techniques. In addition, the staff noted that the applicant’s inspection selection criteria and methodology align with the GALL Report recommendation of 20 percent of the population with a maximum sample of 25 be in a representative sample. The staff’s concern described in RAI B.2.1.21-1 is resolved.

The staff noted that LRA Tables 3.4.2-1 and 3.4.2-3 list components made of gray cast iron and copper alloy (great than 15 percent zinc) that are exposed to steam (internal), which is not included in the B.2.1.21 program description. By letter dated January 21, 2011, the staff issued RAI B.2.1.21-2 requesting that the applicant clarify whether steam (internal) is an environment for the Selective Leaching Materials Program.

In its response dated February 18, 2011, the applicant stated that steam is regarded as a form of treated water and is an environment applicable to selective leaching. The applicant further stated that it had revised the scope of LRA Section B.2.1.21 to include steam as one of the environments applicable to selective leaching.

The staff finds the applicant’s response acceptable because the scope of the Selective Leaching of Materials Program has been expanded to envelope steam as one of the environments applicable to selective leaching, which aligns the program description of this AMP with the components in LRA Tables 3.4.2-1 and 3.4.2-3. The staff’s concern described in RAI B.2.1.21-2 is resolved.

The staff also reviewed the portion of the “detection of aging effects” program element associated with the exception to determine if the program will be adequate to manage the aging effects for which it is credited. The staff’s evaluation of this exception follows.

Exception 1. LRA Section B.2.1.21 states an exception to the “detection of aging effects” program element. The GALL Report recommends visual inspections of the susceptible components and Brinell hardness testing on the inside surfaces of the selected set of components to determine if selective leaching has occurred. The applicant stated that it will use visual inspections and mechanical examination techniques, including Brinell hardness testing or other mechanical examination techniques such as scraping, chipping, or other types of hardness testing, or additional examination methods that become available to the nuclear industry, to determine if selective leaching is occurring on the surfaces of a selected set of components.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception because the form and configuration of many components do not physically allow access for Brinell hardness testing and that additional mechanical testing techniques are needed. The staff finds the program's exception acceptable because the mechanical examination techniques proposed by the applicant, such as scraping, chipping, or other types of hardness testing, are capable to detecting the aging effect of loss of material due to selective leaching.

Regarding the additional examination methods that will become available, the staff does not have sufficient information to evaluate the effectiveness of such methods. By letter dated January 21, 2011, the staff issued RAI B.2.1.21-3 requesting that the applicant state how the new process would be evaluated and qualified to detect selective leaching of material on the surfaces in components made of gray cast iron and copper alloys greater than 15 percent zinc exposed to the environment of interest.

In its response dated February 18, 2011, the applicant stated that the statement "additional examination methods that become available to the nuclear industry" was included in the LRA in anticipation of new technologies that may be available prior to the implementation of this AMP. The applicant further stated that this statement had been removed from the LRA in response to this RAI.

The staff finds the applicant's response acceptable because deletion of such statement removes ambiguity from this AMP. The staff noted that the revised program description (i.e., visual examination and mechanical examination techniques (Brinell hardness testing or other mechanical examination techniques such as destructive testing, when appropriate, scraping, chipping, or other types of hardness testing)) is consistent with the GALL Report AMP XI.M33 Selective Leaching of Materials recommendation of a one-time visual examination and hardness measurement of sample components. The staff's concern described in RAI B.2.1.21-3 is resolved.

Based on its audit and review of the applicant's response to RAIs B.2.1.21-1, B.2.1.21-2, and B.2.1.21-3, the staff finds that elements one through six of the applicant's Selective Leaching of Materials Program, with acceptable exception, are consistent with the corresponding program elements of GALL Report AMP XI.M33 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.21 summarizes operating experience related to the Selective Leaching of Materials Program. The applicant stated that de-aluminization of aluminum-bronze pipe fittings, flanges, and unions exposed to raw seawater has occurred. The applicant also stated that appropriate corrective actions had been taken to replace the aluminum-bronze fittings with copper-nickel components for the piping systems. The applicant further stated that plant-specific guidance for evaluation, repair, or replacement is provided for locations where de-aluminization was found.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 if the applicant 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 effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.21 provides the UFSAR supplement for the Selective Leaching of Materials 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 Tables 3.1-2, 3.2-2, and 3.3-2.

The staff also noted that the applicant committed (Commitment No. 23) to implement the new Selective Leaching of Materials Program for managing aging of applicable components within 5 years prior to the period of extended operation, as stated in the applicant's supplement 2 to its LRA dated November 15, 2010.

The staff noted that the applicant did not include the recommended description in the SRP-LR, which states, "[f]or systems subjected to environments where water is not treated (i.e., the open-cycle cooling water system and the ultimate heat sink), the program also follows the guidance in NRC GL 89-13." However, the staff noted that LRA Sections B.2.1.11 and A.2.1.11 state that the Open-Cycle Cooling Water System Program relies on the recommendations of NRC GL 89-13. The staff finds the applicant's commitment to GL 89-13 in its Open-Cycle Cooling Water System Program sufficient to ensure that the aging effects of selective leaching will be adequately managed.

The staff determined 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 Selective Leaching of Materials Program, the staff determined 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 determined 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 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 One-Time Inspection of ASME Code Class 1 Small-Bore Piping

Summary of Technical Information in the Application. LRA Section B.2.1.23 describes the new One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program as consistent, with an exception, with GALL Report AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small Bore Piping." The applicant stated that this new program will manage the aging effects of cracking in stainless steel small-bore ASME Code Class 1 piping less than 4 in. nominal pipe size (NPS). The applicant further stated that cracking due to SCC, thermal fatigue, and mechanical fatigue will be identified by performing volumetric examinations. The applicant stated that it will select a sample from the total population of ASME Code Class 1 piping based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations as recommended in Materials Reliability Program (MRP)-146, "Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines." The applicant also stated that this sample population will include both butt and socket welds and that, if non-destructive volumetric inspection techniques have not been qualified, it will have the option to remove the weld for destructive examination. The applicant further stated that cracking of small-bore ASME Code Class 1 piping has not been observed.

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 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 Report AMP XI.M35. 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 Report AMP XI.M35, with the exception of the "monitoring and trending" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

GALL Report AMP XI.M35 recommends that a one-time volumetric inspection is an acceptable method for confirming the absence of cracking in ASME Code Class 1 small-bore piping. The GALL Report also states that the inspection of small-bore piping should be performed at a sufficient number of locations to assure an adequate sample. The GALL Report further states that this number, or sample size, will be based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small-bore pipes. Furthermore, MRP-146 provides guidelines for identifying piping susceptible to one subset of cracking, including thermal stratification or turbulent penetrations. During its audit, the staff found that the applicant will inspect for cracking in ASME Code Class 1 small-bore piping using available volumetric examination techniques. The applicant also stated that if non-destructive volumetric examination techniques have not been qualified, it will have the option to remove the weld for destructive examination. Furthermore, the applicant stated during the onsite audit that it will inspect 10 percent of the butt welds and 10 percent of the socket welds and that it may not inspect certain welds based on inaccessibility or high radiation exposure.

It was not clear to the staff if the applicant will either conduct an acceptable volumetric inspection or plan to do destructive examination based on the applicant's program basis document, which states that if an acceptable volumetric examination is not available before the period of extended operation, the applicant will have a choice to do destructive examinations. In addition, it is not clear to the staff if the applicant is proposing to inspect weld locations that are mainly susceptible to thermal loading because the applicant's sampling methodology for the inspection was not presented. It was also not clear to the staff what area (base metal or weld metal) of the socket weld the examination would inspect. By letter dated December 14, 2010, the staff issued RAI B.2.1.23-1 requesting that the applicant do the following:

- clarify how the use of destructive examination is an "option" within the program and UFSAR supplement if an "acceptable" volumetric method isn't available
- clarify what is meant by an "acceptable" volumetric inspection

- describe the methodology for choosing the types of welds to inspect and how this methodology will ensure the AMP adequately manages the effects of all forms of cracking during the period of extended operation
- explain how inaccessible or high radiation exposure welds will be managed by the AMP
- clarify the proposed volumetric examination for socket welds
- justify that the examination volume is sufficient and capable of detecting cracking in the subject socket welds

In its response dated January 13, 2011, the applicant replied to all parts of the request. The applicant stated that, as a way to clarify the use of the word "optional," the program has been modified to specify that, if no demonstrated method of non-destructive volumetric examination capable of detecting cracking in a socket weld is available, the applicant will remove selected weld(s) for destructive examination. The staff finds that a destructive examination is an acceptable alternative because it will provide direct evidence whether aging is occurring when compared to a non-destructive examination. The applicant stated that it modified the program to state that the volumetric inspection technique to be used should be "demonstrated" to have the capability of detecting cracking. The applicant stated that approximately 450 ASME Code Class 1 small-bore welds have been identified and approximately 150 of these are socket welds. The applicant further stated that its inspection will include at least 10 percent of the total number of these welds. The applicant also stated it modified its One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program to state that the sample selection will give priority to location determined to be most susceptible to SCC and to cycling loading (including thermal, mechanical, and vibrational fatigue). The applicant stated that, for specific locations that are not selected because of accessibility or radiation exposures, a location with similar susceptibility will be identified to replace it in the sample selection. The staff finds that the inspection of one location to be representative of another location that is not accessible or has a higher radiation exposure is an acceptable technique because the surrogate inspection, with the same susceptibility to aging, will provide comparable results. Finally, the applicant stated that socket welds will be examined to the maximum extent possible using methods demonstrated to detect cracking in socket welds. The applicant stated that the target of the socket weld will be the weld and not the piping downstream, as described in MRP-146.

Based on its review, the staff finds the applicant's response to RAI B.2.1.23-1 acceptable because the applicant's modifications to the program, as described above, will evaluate an adequate number of welds to manage cracking with either a demonstrated non-destructive volumetric examination or destructive examination, which makes the applicant's program consistent with the GALL Report AMP XI.M35. The staff's concern described in RAI B.2.1.23-1 is resolved.

The staff also reviewed the portions of the "scope of program" program element associated with an exception to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this exception follows.

Exception 1. LRA Section B.2.1.23 states an exception to the "scope of program" program element. The applicant stated that it plans to use the guidance in MRP-146, "Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines," and supplemental guidance in MRP-146-S, "Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines—Supplemental Guidance," to identify piping susceptible to potential effects of thermal stratification or turbulent penetration.

The staff reviewed the “scope of program” program element of GALL Report AMP XI.M35, which states that the program should include measures to verify that degradation does not occur for ASME Code Class 1 small-bore piping in components susceptible to cracking. The “scope of program” program element also states that locations that are susceptible to thermal stratification or turbulent penetration can be determined by MRP-24, “Interim Thermal Fatigue Management Guideline.” The staff noted that MRP-24 was an interim report that was meant to provide early feedback to PWR plant operators and that this report was later updated in the MRP-146 and MRP-146-S to expand on the interim guidelines and provide updated information.

Based on its review, the staff finds the program exception acceptable because the applicant is using updated reports, which expand upon the interim guidelines provided in MRP-24 by incorporating technical knowledge gained from thermal-hydraulic testing and model development, which will provide improved guidance on identifying locations susceptible to cracking from thermal fatigue.

Based on its audit and review of the applicant’s response to RAI B.2.1.23-1, the staff finds that elements one through six of the applicant’s One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program, with an acceptable exception, are consistent with the corresponding program elements of GALL Report AMP XI.M35 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.23 summarizes operating experience related to the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. The applicant stated that this is a new program and that both plant and industrial operating experience will be used to establish the program. The applicant further stated that during its second 10-year ISI period, the inspections included volumetric examination of twenty-seven 2-in. and 3-in. Class 1 butt welds with no cracking being identified. The applicant also stated that it conducted a search of condition reports and did not find degradation or failure in any Class 1 piping less than 4 in. NPS.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 if the applicant 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; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.1.2.23 provides the UFSAR supplement for the One-Time Inspection of ASME Code Class 1 Small-Bore Piping 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 3.1-2. The staff also noted that the applicant committed (Commitment No. 25) to implement the new

One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program within 10 years prior to the period of extended operation for managing aging of applicable components.

The staff determined 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 One-Time Inspection of ASME Code Class 1 Small-Bore Piping, the staff determined 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 determined that the AMP, with an acceptable exception, is adequate to manage the aging effects for which the LRA credits it. The staff concludes that the applicant 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 External Surfaces Monitoring Program

Summary of Technical Information in the Application. LRA Section B.2.1.24 describes the existing External Surfaces Monitoring Program as consistent, with exceptions and an enhancement, with GALL Report AMP XI.M36, "External Surfaces Monitoring." The applicant stated that the program manages the following aging effects:

- hardening and loss of strength due to elastomer degradation
- reduction of heat transfer due to fouling
- loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion and due to fouling
- loss of material due to wear

The applicant also stated that the program consists of periodic inspections of components made of aluminum, cast austenitic stainless steel (CASS), copper alloy, copper alloy with greater than 15 percent zinc, elastomer, galvanized steel, gray cast iron, nickel-alloy, stainless steel, and steel. The applicant further stated that this program uses periodic inspections and walkdowns to monitor material degradation and leakage. In addition, the applicant stated that it conducts visual inspection of component surfaces at least once per refueling cycle.

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 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 Report AMP XI.M36. 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 Report AMP XI.M36, with the exception of the "monitoring and trending" program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of an RAI.

GALL Report AMP XI.M36 recommends periodic plant system inspections and walkdowns to monitor for material degradation under the "monitoring or trending" program element description; however, during the onsite audit, staff identified that the applicant's AMP has in-scope components that cannot be reached for hands-on inspection and, therefore, are not accessible for the tactile inspection as described in the LRA. By letter dated November 18, 2010, the staff issued RAI B.2.1.24-1 requesting that the applicant provide information as to how the tactile techniques would be applied for the in-scope components that are inaccessible for physical manipulation.

In its response dated December 17, 2010, the applicant stated that when an elastomer is inaccessible for tactile inspection, the tactile inspection results of an accessible elastomer of the same construction, in a similar environment, with an equivalent age will be used to assess the condition of the inaccessible elastomer. The applicant also stated that it will apply the same method for determining the condition of metallic components that are inaccessible for visual inspection.

The staff finds the applicant's response acceptable because visual and tactile inspections are capable of identifying the aging effects managed by the program prior to loss of intended function. Also, inspection of accessible components with similar construction, age, and environment to that of inaccessible components is an acceptable method to project the condition of components with similar construction, age, and environment which cannot be inspected because they are inaccessible. The staff noted that this is an acceptable method used to assess the effects of aging for inaccessible components in other AMPs in the GALL Report. The staff's concern described in RAI B.2.1.24-1 is resolved.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with exceptions and enhancement to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions and enhancement follows.

Exception 1. LRA Section B.2.1.24 states an exception to the "scope of program" program element. The applicant stated that its program will manage aging of components made from additional materials such as aluminum, CASS, copper alloy, copper alloy with greater than 15 percent zinc, elastomer, galvanized steel, gray cast iron, nickel alloy, and stainless steel whereas the GALL Report recommends the program for steel components.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception because additional materials are to be covered in the applicant's AMP, which are beyond those recommended by the GALL Report. The staff evaluated the exception and determined the need for additional clarification, which resulted in the issuance of an RAI. GALL Report AMP XI.M36 states that the program consists of periodic visual inspections of steel components such as piping, piping components, ducting, and other components within the scope of license renewal under the "Program Description." However, the applicant indicated that the program will be applied to materials other than steel, which is the material specified in GALL Report for this AMP. By letter dated November 18, 2010, the staff issued RAI B.2.1.24-2 requesting that the applicant provide details on additional inspection methods to be used to ensure that the AMP will adequately address potential aging effects on the additional in-scope materials.

In its response dated December 17, 2010, the applicant stated that the nuclear industry has developed programs to train plant staff on how to correlate an observed condition with possible aging effects. The applicant also stated that personnel who perform inspections as part of the implemented license renewal program will be trained and qualified to identify aging effects in the additional in-scope materials.

The applicant's response did not identify any additional inspection methods necessary to manage the aging effects for the additional in-scope materials because the External Surfaces Monitoring Program includes visual inspections of metallic components and visual inspections and tactile examinations of elastomeric components. The staff noted that visual inspection is an appropriate inspection method for detecting loss of material in metallic components and cracking due to SCC in stainless steel components exposed to outdoor air. The staff also noted that visual inspections coupled with tactile examinations are capable of detecting loss of material, hardening, and loss of strength in flexible elastomeric components.

The staff finds the applicant's response acceptable because the visual inspections and tactile examinations performed as part of the External Surfaces Monitoring Program are capable of detecting the applicable aging effects for the metallic and elastomeric components in the scope of the program, and the personnel performing the inspections will be trained and qualified to identify the aging effects in the additional materials. The staff's concern described in RAI B.2.1.24-2 is resolved.

Exception 2. LRA Section B.2.1.24 states an exception to the "scope of program" and "detection of aging effects" program elements. The applicant stated that the program will address the additional aging effects of hardening and loss of strength, reduction of heat transfer, and loss of material due to galvanic corrosion and wear, whereas the GALL Report recommends this program for managing the aging effect of loss of material.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception because additional aging effects are to be covered in the applicant's AMP, which are beyond those recommended by the GALL Report. The staff evaluated the exception and determined that the exception is adequate because the additional aging effects being managed by the program are addressed with corresponding inspection methods. Specifically, the use of tactile inspection methods will be used to address the additional aging effects being managed for the in-scope elastomers. Additionally, the aging effects of hardening and loss of strength, reduction of heat transfer, and loss of material due to galvanic corrosion on the in-scope metallic components will be adequately covered by the visual inspections included in the program.

Enhancement 1. LRA Section B.2.1.24 states an enhancement to the "scope of program," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements. The applicant stated that the AMP will be enhanced to more specifically address the relevant degradation mechanisms and aging effects, and the inspections will be enhanced to address the detection of corrosion under insulation and the materials included in the program in addition to the materials for which the GALL Report recommends for this program. The applicant also stated that the training requirements for inspectors will be enhanced to address the aging effects that are observable on materials included in the program in addition to the materials for which the GALL Report recommends for this program. The staff evaluated the enhancement against the corresponding program element in GALL Report AMP XI.M36. The staff noted that the applicant's program appropriately identified and addressed the additional inspection considerations required for the full set of in-scope materials and the concerns for detecting corrosion under insulation. The staff finds the program enhancement acceptable because, when implemented, the program elements will be consistent with the recommendations in GALL Report AMP XI.M36.

Based on its audit, and review of the applicant's responses to RAIs B.2.1.24-1 and RAI B.2.1.24-2, the staff finds that elements one through six of the applicant's External Surfaces Monitoring Program, with acceptable exceptions and an enhancement, are consistent with the corresponding program elements of GALL Report AMP XI.M36 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.24 summarizes operating experience related to the External Surfaces Monitoring Program. The applicant stated an instance of operating experience in which heat exchanger outlet lines were observed to have corrosion products on the external surface, which was attributed to reaction with condensation. The applicant also stated that an engineering analysis was conducted after the removal of corrosion products, and the analysis indicated that there were no unacceptable levels of corrosion. The staff noted that an alternative anti-sweat insulation was used to replace the original insulation, which permitted the condensate to be retained on the metal surface of the heat exchanger line.

In another instance of operating experience, the applicant stated that corrosion was observed on the surface of diesel generator piping. The applicant also stated that ultrasonic measurements were taken of the pipe thickness as part of the engineering analysis conducted to determine the extent of corrosion. Although the pipe wall thickness was recorded to be below the original installation value, an engineering evaluation determined that the applicable design code requirements for all design conditions were satisfied; therefore, the measured reduced wall thickness was deemed acceptable by the applicant.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 if the applicant 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; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.24 provides the UFSAR supplement for the External Surfaces Monitoring 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 Tables 3.2-2, 3.3-2, and 3.4-2.

The staff also noted that the applicant committed (Commitment No. 26) to enhance the External Surfaces Monitoring Program prior to entering the period of extended operation. Specifically, the applicant committed to address the scope of the program, relevant degradation mechanisms and effects of interest, the RFO inspection frequency, the inspections of opportunity for possible corrosion under insulation, the training requirements for inspectors, and the required periodic reviews to determine program effectiveness.

The staff determined 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 External Surfaces Monitoring Program, the staff determined 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 determined that the AMP, with the exceptions, 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. 26 prior to the period of extended operation would make the existing AMP consistent with the GALL Report to which it was compared. The staff concludes that the applicant 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 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program

Summary of Technical Information in the Application. LRA Section B.2.1.25 describes the new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program as consistent, with exceptions, with GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The applicant stated that the program will manage the following aging effects:

- cracking due to SCC
- loss of material due to general, pitting, crevice, galvanic and microbiologically-influenced corrosion and due to fouling
- loss of material due to erosion and wear
- reduction of heat transfer due to fouling
- hardening and loss of strength due to elastomer degradation

The applicant further stated that the program will include inspections of opportunity performed during pre-planned periodic system and component surveillances or during maintenance activities when the systems are opened and the surfaces made accessible for visual 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 if 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 Report AMP XI.M38. 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 Report AMP XI.M38, with the exception of the "detection of aging effects," "parameters monitored/inspected," and "acceptance criteria" program elements. For these elements, the staff determined the need for additional clarification, which resulted in the issuance of RAIs.

GALL Report AMP XI.M38 recommends periodic inspections for detection of aging effects prior to the loss of component function. The GALL Report AMP also recommends that locations be chosen to include conditions likely to exhibit the aging effects under the "detection of aging effects" program element description. The applicant's AMP has in-scope components that cannot be reached for hands-on inspection and, therefore, are not accessible for the tactile inspection described in the LRA. By letter dated November 18, 2010, the staff issued RAI B.2.1.25-1 requesting that the applicant provide information as to how the tactile techniques would be applied for the in-scope components that are inaccessible for physical manipulation.

In its response dated December 17, 2010, the applicant stated that when an elastomer is inaccessible for tactile inspection, the tactile inspection results of an accessible elastomer of the same construction, in a similar environment, with an equivalent age will be used to assess the condition of the inaccessible elastomer. The applicant also stated that it will apply the same method for determining the condition of metallic components that are inaccessible for visual inspection.

The staff finds the applicant's response acceptable because visual and tactile inspections are capable of identifying the aging effects managed by the program prior to loss of intended function. Also, inspection of accessible components with similar construction, age, and environment to that of inaccessible components is an acceptable method to project the condition of components with similar construction, age, and environment which cannot be inspected because they are inaccessible. The staff noted that this is an acceptable method used to assess the effects of aging for inaccessible components in other AMPs in the GALL Report. The staff's concern described in RAI B.2.1.25-1 is resolved.

GALL Report AMP XI.M38 recommends that the acceptance criteria be established in the maintenance and surveillance procedures or other established plant procedures under the "detection of aging effects" program element description. The applicant stated that the results of the program's inspections will be used to establish acceptance criteria for the management of aging effects of in-scope components, but no specific information was provided on how this will be conducted. By letter dated November 18, 2011, the staff issued RAI B.2.1.25-2 requesting that the applicant explain how the establishment of new acceptance criteria will be done instead of having previously-established acceptance criteria consistent with the GALL Report recommendations.

In its response dated December 17, 2010, the applicant revised the LRA to remove the statement that acceptance criteria would be established based on results of the program's inspections. The applicant stated that the acceptance criteria for indications of corrosion or fouling will be identified in the appropriate inspection procedures and will be part of the training and qualification program required for all personnel performing the inspections. The applicant also stated that acceptance criteria will include visual indications of corrosion, corrosion byproducts, coating degradation, surface discoloration, scale, deposits, pits, and surface discontinuities. The applicant further stated that personnel performing the inspections will be trained to identify when the as-found condition of the component requires further evaluation using the site corrective action program.

The staff finds the applicant's response acceptable because the applicant will establish acceptance criteria in the inspection procedures, and the personnel performing the inspections will be trained and qualified to identify when the acceptance criteria have not been met and the component condition requires additional evaluation. The staff's concern described in RAI B.2.1.25-2 is resolved.

GALL Report AMP XI.M38 recommends that the visible evidence of corrosion may indicate possible loss of materials. The applicant stated that a thin, light, even layer of oxidation provides protection against further corrosion, which is not accurate for most of the in-scope materials and, when taken in general context, is not accurate. By letter dated November 18, 2011, the staff issued RAI B.2.1.25-3 requesting that the applicant provide technical clarification on the specific in-scope materials to which the subject statement is intended to describe. The applicant was also asked to explain how this statement pertains to monitoring of oxidation by the inspectors in this program.

In its response dated December 17, 2010, the applicant stated that the program will be modified to remove the statement that a thin, light, even layer of oxidation provides protection against further corrosion. The intent of this sentence was to not provide an inspection criterion but to convey that corrosion occurs differently for different materials and in a range of environments. The staff finds the applicant's response acceptable because the applicant corrected a statement in the AMP that, although accurate for some in-scope materials, is not accurate for all of the materials in-scope for the AMP. The staff's concern described in RAI B.2.1.25-3 is resolved.

The staff also reviewed the portions of the "scope of program," and "parameters monitored or inspected" program elements associated with exceptions to determine if 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.2.1.25 states an exception to the "scope of program" program element. The applicant's AMP includes components made from additional materials such as aluminum, CASS, copper alloy, copper alloy greater than 15 percent zinc, elastomer, galvanized steel, gray cast iron, nickel alloy, and stainless steel, whereas the GALL Report recommends the program for steel components.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception because additional materials are to be covered in the applicant's AMP that are not covered by other AMPs. The staff evaluated the exception and determined that the exception is adequate because the inspection methods included in the program are standard methods that are adequate for the detection of age-related degradation that may occur in the materials coved by the applicant's AMP.

Exception 2. LRA Section B.2.1.25 states an exception to the "parameters monitored or inspected" program element. The applicant stated that the program will include inspections for the aging effects of cracking, reduction of heat transfer, and hardening and loss of strength.

The staff reviewed this exception to the GALL Report and noted that the applicant took the exception because additional aging effects is covered in the applicant's AMP that are beyond those recommended by the GALL Report. The staff evaluated the exception and determined that the exception is adequate because the additional aging effects being managed by the program are addressed with corresponding standard inspection methods. Specifically, the use of tactile inspection methods and their correlation to inaccessible components will be used to address the additional aging effects being managed for the in-scope elastomers.

Based on its audit, and review of the applicant's responses to RAIs B.2.1.25-1, B.2.1.25-2, and B.2.1.25-3, the staff finds that elements one through six of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, with acceptable exceptions, are consistent with the corresponding program elements of GALL Report AMP XI.M38 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.25 summarizes operating experience related to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The applicant described one instance of operating experience in which corrosion was detected inside the shell of a storage tank heat exchanger. The applicant stated that the observation was followed by an engineering assessment during which it was determined that the corrosion was not significant and no further action was indicated at the time. The applicant further stated that, during a followup inspection, an ultrasonic examination was performed, and parts of the heat exchanger were measured to be below the minimum wall thickness requirement. A base metal repair was performed prior to returning the heat exchanger to service.

In another instance of operating experience, the applicant described a case in which corrosion was found on an internal part of a screen wash system valve during a maintenance activity. The applicant stated that the valve was replaced and based on the knowledge of this instance of observed degradation, an extent of condition evaluation was performed, on valves in similar service environments that could potentially be subjected to the same corrosion effect. The applicant stated that preventive maintenance activities were developed for the disassembly and inspection of all similar valves with a frequency of every 6 years.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 if the applicant 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; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.25 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 noted 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 noted that the applicant committed (Commitment No. 27) 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 determined 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 Program, the staff determined 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 determined that the AMP, with the exceptions, is adequate to manage the aging effects for which the LRA credits it. Also, the staff noted the program's implementation via Commitment No. 27 prior to the period of extended operation. The staff concludes that the applicant 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).

3.0.3.2.16 Lubricating Oil Analysis Program

Summary of Technical Information in the Application. LRA Section B.2.1.26 describes the existing Lubricating Oil Analysis Program as consistent, with an exception and enhancements, with GALL Report AMP XI.M39, "Lubricating Oil Analysis." The applicant stated that the Lubricating Oil Analysis Program is an existing program that performs oil condition monitoring activities to manage the aging effects of loss of material due to galvanic, general, pitting, crevice, microbiologically-influenced corrosion, fouling, and heat transfer degradation due to fouling. The applicant further stated that the purpose of the Lubricating Oil Analysis Program is to obtain and analyze lubricating oil samples from plant equipment to ensure that the oil quality is maintained within established limits. The applicant also stated that the program includes sampling and analysis of lubricating oil for components within the scope of license renewal and subject to an AMR.

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 they are bounded by the conditions for which the GALL Report was evaluated.

The staff also reviewed the portions of the "parameters monitored or inspected" and "detection of aging effects" program elements associated with an exception and enhancements to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exception and enhancements follows.

Exception 1. LRA Section B.2.1.26 states an exception to the "parameters monitored or inspected" program element. The GALL Report recommends that for components that do not have regular oil changes, tests for viscosity, neutralization number, and flash point may be used to determine lubricating oil suitability for continued use. Alternatively, this program element in the LRA states that Seabrook does not sample for flash point in lubricating oil samples. Instead, the applicant stated that when there is a potential for lubricating oil contamination by fuel, Seabrook will test the samples for fuel dilution. The applicant further stated that testing for fuel dilution is equivalent to testing for flash point because either test will provide an indication of fuel in-leakage.

The staff reviewed this exception to the GALL Report and noted that the applicant takes exception to the GALL Report in that Seabrook does not sample for flash point in lubricating oil samples. The staff determined that more information was needed. By letter dated December 14, 2010, the staff asked the applicant to discuss the method Seabrook uses to determine fuel dilution and explain how it compares to sampling for flash point.

In its response by letter dated January 13, 2011, the applicant stated that Seabrook will add flash point testing as a requirement for in-scope diesel engine lube oil analysis. The applicant indicated that ASTM Standard D 6224-98, "Standard Practice for In-Service Monitoring of Lubricating Oil for Auxiliary Power Plant Equipment," recommends flash point testing to diesel engine oils. As such, the applicant stated that flash point is of little significance for determining the degree of degradation of used oil since normal degradation has little effect on the flash point.

The applicant stated that Seabrook will limit the flash point testing to those lube oil samples that have the potential for contamination by fuel. The applicant stated that potential for fuel contamination is limited to the two main emergency diesel generators and the two diesel fire pumps.

The staff finds this exception acceptable and consistent with the one described in the GALL Report Section XI.M39 because the program will be enhanced to include flash point testing for lube oil samples that have the potential for fuel contamination, the potential for which is limited to the two main emergency diesel generators and the two diesel fire pumps. Flash point testing is an acceptable method used to determine fuel contamination in lubricating oil for components that do not have regular oil changes such as the two main emergency diesel generators and the two diesel fire pumps.

On the basis of its review, that staff finds this program exception acceptable because this program will be enhanced to include flash point testing, which is recommended by the GALL Report AMP XI.M39.

Enhancement 1. LRA Section B.2.1.26 states an enhancement to the “parameters monitored or inspected” program element. This enhancement expands on the existing program element by adding an attachment list that specifies the required equipment for the program, sampling frequency, discussion on the required periodic oil changes, and includes the associated lube oil analysis required. In a letter dated January 13, 2011, in response to RAIs by letter dated December 14, 2010, the applicant modified this enhancement to include flash point testing for lubricating oil that has the potential for contamination by fuel.

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 of GALL Report AMP XI.M39.

Enhancement 2. LRA Section B.2.1.26 states an enhancement to the “detection of aging effects” program element. This enhancement expands on the existing program element by adding a requirement to sample the oil for the reactor coolant pump oil collection tanks.

On the basis of its review, the staff finds this enhancement acceptable because periodic sampling and compliance with acceptance criteria ensures lube oil contaminants do not exceed acceptable levels, thereby preserving the environment that could lead to the aging effects of loss of material. Also, when it is implemented, prior to the period of extended operation, it will make the program consistent with the recommendations of GALL Report AMP XI.M39.

Enhancement 3. LRA Section B.2.1.26 states an enhancement to the “detection of aging effects” program element. This enhancement expands on the existing program element by adding a requirement to perform a one-time ultrasonic thickness measurement of the lower portion of the reactor coolant pump oil collection tanks prior to the period of extended operation.

On the basis of its review, the staff finds this enhancement acceptable because compliance with acceptance criteria ensures lube oil contaminants do not exceed acceptable levels, thereby preserving the environment that could lead to the aging effects of loss of material. Also, when it is implemented, prior to the period of extended operation, it will make the program consistent with the recommendations of GALL Report AMP XI.M39.

Based on its audit, the staff finds that program elements one through six of the applicant's Lubricating Oil Analysis Program, with acceptable exception and enhancements, are consistent with the corresponding program elements of GALL Report AMP XI.M39 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.1.26 summarizes operating experience related to the Lubricating Oil Analysis Program. The staff reviewed this information and interviewed the applicant's technical personnel to confirm that the applicable aging effects and industry- and plant-specific operating experience have been reviewed by the applicant and are evaluated in the GALL Report. During the audit, the staff independently confirmed that the applicant adequately incorporated and evaluated operating experience related to this program.

The staff reviewed the operating experience information, in the application and during the audit, to determine if 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 if the applicant 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 be ineffective 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 application 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; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.26 provides the UFSAR supplement for the Lubricating Oil Analysis Program. The staff reviewed the 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 Tables 3.2-2, 3.3-2, and 3.4-2.

The staff also noted that the applicant committed (Commitment Nos. 28, 29, and 30) to enhance the Lubricating Oil Analysis Program prior to entering the period of extended operation. Specifically, the applicant committed to do the following:

(1) Enhance the program to add required equipment, lube oil analysis required, sampling frequency, and periodic oil changes. In addition, the program will be required to include flash point testing when there is a potential for contamination of the lubricating oil by fuel.

(2) Enhance the program to sample the oil for the Reactor Coolant pump oil collection tanks.

(3) Enhance the program to require the performance of a one-time ultrasonic thickness measurement of the lower portion of the Reactor Coolant pump oil collection tanks prior to the period of extended operation.

The staff determined 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 Lubricating Oil Analysis Program, the staff determined 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 determined 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 Nos. 28, 29, and 30 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 demonstrated that the effects of aging will be adequately managed so that the intended function will be maintained consistent with the CLB for the period of extended operation, 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 ASME Code Section XI, Subsection IWL Aging Management Program[1]

Summary of Technical Information in the Application. LRA Section B.2.1.28 describes the existing ASME Code Section XI, Subsection IWL AMP as consistent, with enhancements, with GALL Report AMP XI.S2, "ASME Code Section XI, Subsection IWL." This program manages aging effects to the reinforced concrete containment building and complies with examination requirements in 10 CFR 50.55a. According to the applicant, the examinations are performed in accordance with ASME B&PV Code, Section XI, Subsection IWL, "Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants." The applicant further states that all accessible reinforced concrete containment components are within the scope of this program. In addition, the applicant will evaluate the acceptability of concrete in inaccessible areas of the containment when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas.

Summary of Staff Evaluation. The staff has reviewed the various elements of the concrete containment aging management program and found them consistent with the corresponding program elements of GALL Report AMP XI.S2; however, based on the lack of understanding of alkali-silica reaction (ASR) and its impacts, the staff determined that the applicant needs to enhance the ASME Code Section XI, Subsection IWL aging management program to demonstrate the effects of ASR will be adequately managed. The enhancements are required to the program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." The staff is concerned that the applicant has not performed adequate testing and evaluation of the cracked area in the containment to determine if the cracks are due to ASR in the concrete, which has affected other nearby structures. In addition, the staff is concerned that the applicant has not implemented permanent measures to dewater the annular space between the containment and containment enclosure buildings. The staff's concerns are tracked as Open Items OI 3.0.3.1.9-1 and OI 3.0.3.2.18-1. Until these open items are resolved, the staff will not be able to conclude that the effects of aging will be adequately managed.

Staff Evaluation. The Seabrook containment is a concrete cylinder topped with a hemispherical dome, supported on a reinforced concrete foundation mat. The concrete containment is completely contained within the containment enclosure building and is not exposed to an outdoor environment. The containment enclosure building is also a concrete cylinder with a hemispherical dome. There is an annular space of five feet between the containment and the

[1] The applicant submitted a supplement to the LRA dated May 16, 2012, which addresses a plant-specific aging management program entitled "Alkali-Silica Reaction Monitoring Program." The staff is currently reviewing this supplement, and therefore, its evaluation is not included in this SER with open items.

containment enclosure building. The below grade portion of the containment is not in contact with the soil or ground water. However, for some time in the past, the bottom 6 feet of the concrete containment cylinder was in contact with groundwater that leaked through the containment enclosure building and filled the annular space. The groundwater from this area has since been removed, and the applicant has committed to keep this annular space dry in the future. Two isolated areas of the concrete containment that were previously exposed to the groundwater have indications of cracking.

This section of the SER addresses the staff's review and evaluation of the applicant's aging management program for the Seabrook concrete containment only. The aging management program for the other in-scope concrete structures, including the containment enclosure building, is described in Section 3.0.3.2.18 of this SER.

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 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 Report AMP XI.S2. 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 Report AMP XI.S2, with the exception of the “acceptance criteria” program element. For this element, the staff determined the need for additional clarification, which resulted in the issuance of RAIs.

GALL Report AMP XI.S2 recommends the acceptance criteria for concrete containments provided in IWL-3000. For concrete surfaces, the acceptance criteria rely on the determination of the “responsible engineer” regarding whether there is any evidence of damage or degradation sufficient to warrant further evaluation or repair. In addition, GALL Report AMP XI.S2 states that quantitative acceptance criteria based on the “evaluation criteria” provided in Chapter 5 of ACI 349.3R may also be used to augment the qualitative assessment of the responsible engineer. During its audit, the staff found that the preventive maintenance work orders that are used for tracking and identifying conditions and the site procedure that describes acceptance criteria for concrete containment surface evaluations do not implement the three-tier evaluation criteria in Chapter 5 of ACI 349.3R. The staff also found that visual inspection results for the concrete containment indicated numerous areas of spalled concrete that equaled or exceeded a depth of 1 in. In accordance with evaluation criteria in ACI 349.3R-02, Section 5.1, spalled areas that exceed a depth of $^{3}/_{8}$ in. and 4 in. in any dimension must be evaluated.

By letter dated November 18, 2010, the staff issued RAI B.2.1.28-1 requesting that the applicant provide the basis for acceptance criteria in its site procedure for evaluating concrete containment surfaces. The applicant was also asked to describe actions taken to address issues identified in NRC IN 2010-14, “Containment Concrete Surface Condition Examination Frequency and Acceptance Criteria.” In its response dated December 17, 2010, the applicant stated the following:

> Any Containment concrete degradation identified during IWL Examinations is documented (per the implementing procedure) on Examination Forms, using the guidance of ACI 349.3R and ACI 201.1R for condition quantification, description and terminology. The degraded area is marked in the field with an identifying label to guide the Responsible Engineer's review, and subsequent Examination review. An Action Request (AR) is generated for Examination Forms that document degradation, requiring an Evaluation by the Responsible Engineer.

> The Forms and Evaluations are retained and reviewed prior to the next Examination. During the subsequent Examination, previously reported areas are re-examined to determine if there has been any change in their condition. The retained Forms and Evaluations from each successive Examination will be maintained up to and through the Period of Extended Operation, thereby creating a continuous record of the condition of the Containment concrete.

The applicant also stated that, in response to IN 2010-14, “Containment Concrete Surface Condition Examination Frequency and Acceptance Criteria,” the Seabrook Inservice Inspection Procedure Primary Containment Section XI IWL Program was revised in October 2010 to include the guidance of ACI 201.1R and ACI 349.3R for identifying degradation during general visual examinations.

The staff finds that the revision made to the Seabrook Inservice Inspection Procedure Primary Containment Section XI IWL Program to include guidance in ACI 349.3R is acceptable because use of quantitative acceptance criteria based on the “evaluation criteria” provided in Chapter 5 of ACI 349.3R makes the applicant’s AMP consistent with GALL Report AMP XI.S2. The staff’s concern described in RAI B.2.1.28-1 is resolved.

By letter dated November 18, 2010, the staff issued RAI B.2.1.28-2 requesting that the applicant describe the methods used to evaluate spalled areas that exceed a depth of $^{3}/_{8}$ in. and 4 in. in any dimension. The applicant was also asked to provide findings from the most recent engineering evaluation report that was prepared to comply with ASME Code Section XI, Subsection IWL-3310 requirements.

In its response dated December 17, 2010, the applicant stated that prior to August 18, 2010, IWL examinations were conducted in accordance with ASME Code Section XI, Subsection IWL, of the 1995 Code with 1996 Addendum. During this time, deficiencies were reported in qualitative terms and evaluations were conducted by the responsible engineer, a licensed professional engineer, using the methodology described in the response to RAI B.2.1.28-1. The applicant further stated that the September 2010 IWL examination was conducted in accordance with ASME Code Section XI, Subsection IWL, of the 2004 Code and with the guidance of ACI 201.1R and ACI 349.3R. For this examination, deficiencies were reported in the quantitative terms of ACI 349.3R and evaluations were conducted by the responsible engineer, a licensed professional engineer, with the guidance of ACI 349.3R. The applicant also provided the following summary of findings from the September 2010 IWL examination:

> Five Action Requests (ARs) were issued during the ASME Code Section XI, IWL examinations of the Containment concrete; eighty-four (84) deficient areas were identified that required an Engineering Evaluation.
>
> Each of the reported discontinuities in the Containment concrete were individually reviewed and evaluated by Design Engineering. All of the reported discontinuities were accepted-as-is with no further technical evaluation or remediation, based on the criteria of ACI 349.3R.

The staff finds that use of acceptance criteria in ACI 349.3R to evaluate concrete containment deficiencies and discontinuities is acceptable because use of these criteria makes the applicant’s program consistent with GALL Report AMP XI.S2. The staff’s concern described in RAI B.2.1.28-2 is resolved.

The staff also reviewed the portions of the “acceptance criteria,” “parameters monitored or inspected,” and “preventive actions” program elements associated with enhancements to determine if 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 “acceptance criteria” program element. This enhancement involves including the definition of “responsible engineer” (registered professional engineer) in the applicant’s procedure for implementing its ASME Code Section XI, Subsection IWL AMP.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S2. The staff noted that the applicant’s procedure for implementing its ASME Code Section XI, Subsection IWL AMP requires that the responsible engineer be a registered professional engineer experienced in evaluating the inservice condition of structural concrete and knowledgeable of the design and construction codes and other criteria used in design and construction of concrete containments. The staff finds this enhancement involving the definition of responsible engineer acceptable because it is consistent with the guidance provided in GALL Report AMP XI.S2 and IWL-2310 requirements.

Enhancement 2. By letter dated December 17, 2010, the applicant revised LRA Section B.2.1.28 to include an enhancement to the “parameters monitored or inspected” program element. This enhancement involves performing confirmatory testing and evaluation of the containment structure concrete. The testing and evaluation will determine the concrete compressive strength, the presence or absence of alkali-silica reaction (ASR), the concrete modulus of elasticity, and the presence or absence of rebar degradation. The testing and evaluation will be completed prior to the period of extended operation. However, by letter dated August 11, 2011, the applicant eliminated this enhancement and associated Commitment 51 from the LRA. The applicant stated that program enhancement and commitment confirmatory testing cannot be made until aging effects due to ASR are fully understood. The applicant further stated that information regarding the planned approach to addressing ASR degradation throughout the site will be included in the engineering evaluation scheduled to be completed by March 2012.

The staff reviewed the applicant's response concerning the elimination of Enhancement 2 and Commitment 51 and found it unacceptable. The staff's basis for this conclusion is described later in this SER section. This item is tracked as Open Item OI 3.0.3.2.18-1.

Enhancement 3. By letter dated December 17, 2010, the applicant revised LRA Section B.2.1.28 to include an enhancement to the “preventive actions” program element. This enhancement involves implementing measures to maintain the exterior surface of the containment structure from elevation -30 ft to +20 ft in a dewatered state. These measures will be implemented prior to the period of extended operation.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S2. The staff noted that no preventive actions are specified in GALL Report AMP XI.S2. However, maintaining the exterior surface of the containment structure from elevation -30 ft to +20 ft in a dewatered state is an appropriate preventive action because it will ensure that the exterior surface of the concrete containment will not be exposed to water that could contribute to cracking due to expansion and reaction with aggregates. In addition, during September 2011, NRC inspectors examined the subject area and found the exterior surface of the containment to be in a dewatered state. Portable sump pumps are used to dewater the area. However, the staff is concerned that until now the applicant has not implemented permanent measures for dewatering and revised procedures for routine inspection of this area. The staff's concern is tracked as Open Item OI 3.0.3.1.9-1.

Based on its audit, and review of the applicant's responses to RAI B.2.1.28-1 and RAI B.2.1.28-2, the staff finds that elements one through six of the applicant's ASME Code Section XI, Subsection IWL AMP, with acceptable enhancements, are consistent with the corresponding program elements of GALL Report AMP XI.S2. However, as discussed below, the staff has determined that the applicant needs to resolve Open Item OI 3.0.3.2.18-1 by enhancing program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," of the ASME Code Section XI, Subsection IWL AMP to demonstrate the effects of ASR will be adequately managed.

Operating Experience. LRA Section B.2.1.28 summarizes operating experience related to the ASME Code Section XI, Subsection IWL AMP. According to the applicant, this program is implemented through Seabrook's Containment Surface Inspection Program, and the containment structure concrete has been found to be in good condition during inspections performed in accordance with ASME Code Section XI, Subsection IWL. The applicant further stated that containment inspections performed in 2002, 2005, and 2008 were completed satisfactorily with no indication of degradation of the concrete surfaces.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 plant operating experience information to determine if the applicant adequately incorporated and evaluated operating experience related to this program.

During its review, the staff identified 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. The staff determined the need for additional clarification, which resulted in the issuance of RAIs.

In LRA Section B.2.1.28, the applicant stated that concrete degradation due to aggressive chemical attack is an aging effect applicable to Seabrook and that the Structures Monitoring Program addresses the plan and specific details to determine the effects of aggressive chemical attack on the concrete. The applicant further stated that an evaluation will be conducted after the testing in the plan is performed, and, if required, actions will be provided using the corrective action process for concrete under the Structures Monitoring Program and the ASME Code Section XI, Subsection IWL AMP.

During the audit, the staff found that initial testing results for concrete samples obtained from below-grade areas of other safety-related structures indicate that the concrete in these areas is exhibiting cracking due to expansion and reaction with aggregates. In addition, the staff learned that the applicant observed about 6 ft of water accumulation in the annulus between the containment and the enclosure building. Although water is a contributing factor to cement-aggregate reactions as discussed in ACI 349.3R-02, Section 4.2.5, the applicant stated that the containment concrete in the annulus does not exhibit evidence of cracking due to expansion and reaction with aggregates. A review of Seabrook condition reports by the staff did not identify inspection findings that discussed cracking of concrete due to expansion and reaction with aggregates or nondestructive or destructive test data that quantify the magnitude or extent of cracking of accessible above-grade and below-grade portions of the concrete containment.

By letter dated November 18, 2010, the staff issued RAI B.2.1.28-3 requesting that the applicant provide information about the test method or procedure used to confirm that the exterior containment concrete surface between elevation -30 ft and +20 ft is not experiencing cracking due to expansion and reaction with aggregates. The applicant was also asked to confirm that the compressive strength and modulus of elasticity of the containment concrete between elevation -30 ft and +20 ft are not affected by cracking due to expansion and reaction with aggregates. The staff also asked the applicant to provide results of any existing or planned compressive, tensile, and modulus of elasticity of concrete tests for core samples taken from the concrete containment between elevation -30 ft and +20 ft.

In its response dated December 17, 2010, the applicant stated that the 2010 ASME Code Section XI, Subsection IWL 5-year inspection of the containment structure was performed using the guidance of ACI 349, "Evaluation of Existing Nuclear Safety-Related Concrete Structures." The applicant also stated that there has been no sign of detrimental cracking in the containment structure based on the inspection performed using the guidance of ACI 349.3R. The applicant further stated that in the absence of detrimental cracking, there has been no reasonable expectation for loss of compressive strength or loss of modulus of elasticity. In addition, the applicant will perform confirmatory testing and evaluation of the containment structure concrete (Commitment No. 51). The applicant indicated that the testing and evaluation will determine the concrete compressive strength, the presence or absence of ASR, the concrete modulus of elasticity, and the presence or absence of rebar degradation. The testing and evaluation will be completed prior to the period of extended operation.

Based on its review, the staff found the applicant's response to RAI B.2.1.28-3 concerning confirmatory testing and evaluation of the Containment Structure concrete unacceptable. The staff was concerned that the applicant's commitment (Commitment 51) to complete confirmatory testing and evaluation of the containment structure prior to the period of extended operation in March 2030 does not adequately support development of an appropriate aging management program. Furthermore, contrary to the applicant's response in the RAI B.2.1.28-3, dated December 17, 2010, the applicant informed the staff during the license renewal inspection in April 2011 that a portion of containment concrete above the base slab has indications of cracking of concrete. Therefore, by letter dated June 28, 2011, the staff issued Follow-up RAI B.2.1.28-3 requesting that the applicant verify whether or not the enhancement and Commitment 51, regarding testing to confirm containment concrete properties, made in the letter dated December 17, 2010, is still valid, and provide detailed plans to monitor the extent of cracking and expansion in concrete.

In its response dated August 11, 2011, the applicant stated that program enhancements and commitment to confirmatory testing cannot be made until the aging effects of the ASR are fully understood. The applicant also stated that information regarding the planned approach to addressing ASR degradation throughout the site will be included in an engineering evaluation scheduled to be completed in March 2012. The application also deleted Commitment 51.

In a subsequent letter dated March 30, 2012, the applicant stated that the ASME Section XI, Subsection IWL, 5-year inspection of the containment structure was performed in 2010 using the guidance of ACI 349. The applicant also stated that additional inspections of the exterior surface of the containment structure were performed in September 2011. The results of these inspections show a maximum crack width of 8 mils, which is less than the 15 mil criteria for acceptance without further evaluation in the first tier of Structural Monitoring Program. The inspection revealed two isolated locations of the containment exterior surface that exhibit pattern cracking that may be indicative of ASR. The applicant further stated that although the crack width does not meet the Structural Monitoring Program threshold for further evaluation, these two locations will be included for further evaluation, and further inspections will be performed. Core samples have not been taken and are not currently planned.

The staff reviewed the applicant's response and finds it unacceptable because the applicant has not confirmed if the cracks are passive or active. The applicant has stated that the crack pattern may be due to ASR which is indicative of active cracking. Active cracking observed in a structure is required to be investigated because cracking damage can continue or intensify. The 15 mil crack width acceptance criteria in the ACI 349.3R, incorporated in Structures Monitoring Program, is only for passive cracks. ACI 349.3R, Section 5.1 defines passive cracks as those having an absence of recent growth and an absence of other degradation mechanism at cracks. The staff believes that confirmatory testing is required to determine if ASR is present in the Containment Concrete. In addition, the applicant needs to enhance the program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," of the ASME Section XI, Subsection IWL AMP for inspection of containment concrete to detect the presence of ASR and manage aging of the ASR affected areas of the concrete containment. Therefore, the staff concern is unresolved and identified as Open Item OI 3.0.3.2.18-1.

In its response to RAI B.2.1.28-3, dated December 17, 2010, the applicant also stated it will implement measures to maintain the exterior surface of the containment structure, from elevation -30 ft and +20 ft, in a dewatered state (Commitment No. 52). These measures will be in effect prior to the period of extended operation. In a subsequent letter dated April 14, 2011, the applicant revised Commitment No. 52 and committed to implement measures by December 31, 2012, to maintain the exterior surface of the containment concrete from elevation -30 feet to +20 feet dewatered. During the December 31, 2010, inspection, NRC inspectors examined the subject area and found it in a dewatered state. Portable sump pumps are used to dewater the area. However, as discussed above, the staff is concerned that until now the applicant has not implemented any permanent measures for dewatering and revised procedures for routine inspection of this area. The staff's concern is tracked as Open Item OI 3.0.3.1.9-1.

By letter dated November 18, 2010, the staff issued RAI B.2.1.28-4 requesting that the applicant provide plans and schedules for the following:

- conducting a baseline inspection of the condition of accessible above-grade and below-grade portions of the concrete containment in accordance with ACI 349.3R requirements
- obtaining nondestructive or destructive test data for quantifying the mechanical properties (compressive strength, tensile strength, and modulus of elasticity) of concrete in areas that have experienced cracking due to expansion and reaction with aggregates

In its response dated December 17, 2010, the applicant stated that the most recent ASME Code Section XI, Subsection IWL examination of containment concrete was completed in October 2010. This examination of the containment concrete consisted of general visual and detailed visual examinations consistent with the criteria in ACI 201.1-92 and ACI 349.3R-02. The applicant also stated that these two ASME Code IWL concrete examinations will serve as the baseline for future examinations of containment concrete, which are performed at 5-year intervals. The applicant further stated that the containment is enclosed by the containment enclosure building, and the inspection is based on one environment which is air-indoor uncontrolled. Measures that the applicant will take to determine the integrity of the containment concrete and steel reinforcing bars in areas that have experienced cracking due to expansion and reaction with aggregates are discussed in its response to RAI B.2.1.28-3. As discussed, above, the staff has determined that the applicant needs to resolve Open Item OI 3.0.3.2.18-1 by enhancing program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," of the ASME Code Section XI, Subsection IWL AMP to demonstrate the effects of ASR will be adequately managed.

UFSAR Supplement. LRA Section A.2.1.28 provides the UFSAR supplement for the ASME Code Section XI, Subsection IWL AMP. 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 3.5-2.

The staff also noted that the applicant committed (Commitment Nos. 31 and 52) to enhance the ASME Code Section XI, Subsection IWL AMP prior to entering the period of extended operation. Specifically, the applicant committed to include the definition for "Responsible Engineer" in its procedure for implementing its ASME Code Section XI, Subsection IWL AMP. The applicant also committed to implement measures to maintain the exterior surface of the containment structure, from elevation -30 feet to +20 feet, in a dewatered state. However, the staff is concerned that, until now, the applicant has not implemented Commitment 52 to maintain the exterior surface of the containment in a dewatered state.

The staff finds that until Open Items OI 3.0.3.1.9-1 and OI 3.0.3.2.18-1 are resolved, the information in the UFSAR supplement, as required by 10 CFR 54.21(d) is not adequate.

Conclusion. The staff concludes that the applicant has not 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 applicant needs to resolve Open Item OI 3.0.3.2.18-1 by enhancing the program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," of the ASME Section XI, Subsection IWL AMP to demonstrate that the effects of the ASR in the concrete containment will be adequately managed. Once Open Items OI 3.0.3.1.9-1 and OI 3.0.3.2.18-1 are resolved, the applicant will need to make appropriate changes to the UFSAR supplement for this AMP to include a complete summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.18 Structures Monitoring Program[2]

Summary of Technical Information in the Application. LRA Section B.2.1.31 describes the existing Structures Monitoring Program as being consistent, with enhancements, with GALL Report AMP XI.S6, "Structures Monitoring Program." In the LRA, the applicant stated that AMP B.2.1.31, "Structures Monitoring Program," is implemented through the Seabrook Maintenance Rule Program and integrates the Masonry Wall Program and RG 1.127, "Inspection of Water Control Structures Associated with Nuclear Power Plants," Program. These programs are existing and consistent with the program elements in GALL Report AMP, XI.S5, "Masonry Wall Program," GALL Report AMP XI.S6, "Structures Monitoring Program," and GALL Report AMP, XI.S7, "RG 1.127, Inspection of Water Control Structures Associated with Nuclear Power Plants," with enhancements.

[2] The applicant submitted a supplement to the LRA dated May 16, 2012, which addresses a plant-specific aging management program entitled "Alkali-Silica Reaction Monitoring Program." The staff is currently reviewing this supplement, and therefore, its evaluation is not included in this SER with open items.

In the LRA, the applicant stated that the Structures Monitoring Program performs visual inspections of structures and structural components for the detection of aging effects specific to the particular structure at a frequency determined by the characteristics of the environment in which the structure is located. These inspections are performed at an interval not to exceed 5 years (plus or minus 1 year) for structures in a harsh environment. The applicant also stated that a harsh environment is defined as one that is in an area that is routinely subjected to outside ambient conditions of very high temperature, high moisture or humidity, frequent large cycling of temperatures, frequent exposure to caustic materials, or extremely high radiation levels. Structures not found in areas qualifying as a harsh environment are classified as being in a mild environment and are inspected on a 10-year basis. Individuals performing the inspections and interpreting the results have expertise in the design and inspection of steel, concrete, and masonry structures and are either licensed professional engineers experienced in this area or will be working under the direction of a licensed professional engineer with expertise in this area. The applicant further stated that parameters monitored meet the requirements of ACI 349.3R-96, "Evaluation of Existing Nuclear Safety Related Concrete Structures," and ASCE 11-90, "Structural Condition Assessment of Buildings." Identification of concrete deficiencies is based on guidance provided in ACI 201.1R-2, "Guide for Making a Condition Survey of Concrete in Service," and acceptance guidelines use a three-tier hierarchy similar to that described in ACI 349.3R-96 9 (i.e., acceptable, acceptable with deficiencies, or unacceptable).

In the LRA, the applicant stated that aggressive subsurface environments are monitored by sampling the groundwater at 5-year intervals for chloride concentration, sulfate concentration, and pH. Inaccessible areas, such as buried concrete foundations, will be examined during inspections of opportunity or during focused inspections at 5-year intervals. The applicant also stated that although Seabrook has no block or concrete masonry walls used in Category I structures, masonry walls in structures and buildings (fire pumphouse, nonessential switchgear room, turbine building and yard structure station blackout) performing nonsafety-related functions are monitored for cracking and evaluated under the Structures Monitoring Program. Periodic visual inspections of water control and flood protective structures are within the scope of the Structures Monitoring Program and are inspected under the Maintenance Rule Program.

<u>Summary of Staff Evaluation</u>. The staff has reviewed the various elements of the Structures Monitoring Program and found them to be consistent with corresponding elements of GALL Report AMP; however, based on the lack of understanding of alkali-silica reaction (ASR) and its impacts, the staff determined that the applicant needs to enhance the Structures Monitoring Program to manage the effects of ASR. The enhancements are required to the program elements "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria." This issue is being tracked as Open Item OI 3.0.3.2.18-1. Until this open item is resolved, the staff will not be able to conclude that the effects of aging will be adequately managed.

<u>Staff Evaluation</u>. This section of the SER addresses the staff's review and evaluation of the applicant's aging management program for all license renewal in-scope concrete structures and masonry walls at Seabrook plant except for the concrete containment structure. The aging management program for the containment structure is described in Section 3.0.3.2.17 of this SER.

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 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 Report AMPs XI.S5, XI.S6, and 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 Report AMPs XI.S5, XI.S6, and XI.S7.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements associated with enhancements to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the enhancements follows.

The staff noted that inclusion of opportunistic and focused inspections on a 5-year interval addresses GALL Report recommendations for examination of exposed portions of the below-grade concrete when excavated for any reason and development of a plant-specific AMP for plants with aggressive groundwater and soil that have experienced degradation. However, the staff also noted that the applicant inspected the remaining in-scope structures on a 5- or 10-year basis, depending on the structure's environment. The staff believes it may be acceptable to inspect structures on an interval greater than 5 years; however, the applicant must provide a list of the structures inspected under the longer interval along with a description of their environments and justification for the interval extension. Therefore, by letter dated January 5, 2011, the staff requested the applicant to identify the structures that will be inspected on a 10-year frequency along with their environments and a summary of past degradation.

In its response, dated February 3, 2011, the applicant stated that a harsh environment is an area routinely subjected to outside ambient conditions, high moisture or humidity, very high ambient temperatures or frequent large cycling of temperatures (including freezing and thawing), frequent exposure to caustic materials, or extremely high radiation levels. A mild environment is one that is not harsh. The applicant further stated that, based on ACI 349.3R, the evaluation and inspection frequency varies according to the environment, from 5–10 years. In accordance with ACI-349.3R, the interior, above-grade portions of the following in-scope of license renewal structures are in a mild environment and, therefore, subject to a 10-year inspection frequency:

- the containment enclosure ventilation area
- the control building
- the diesel generator building
- the waste process building and tank farm (selected areas are harsh)
- the emergency feedwater pumphouse building including pre-action valve building
- the fuel storage building
- the primary auxiliary building (selected areas are harsh)
- the turbine generator building
- the fire pumphouse
- the steam generator blowdown recovery building
- the non-essential switchgear building

The applicant also stated that it classified the following structures, following ACI-349.3R guidance, to be in a harsh environment and, therefore, subject to a 5-year inspection:

- all in-scope below-grade structures (interior and exterior)
- all exterior above grade structures
- all structures inside primary containment
- designated areas of the tank farm and of the primary auxiliary building

- the service water pumphouse
- the circulating water pumphouse
- the intake transition structure
- the discharge transition structure
- the service water cooling tower revetment

The applicant then reiterated that the past degradation of these structures is discussed in the body of the program in the LRA.

The staff reviewed the applicant's response and found that it needed clarification regarding how frequently the spent fuel pool would be inspected and whether or not the inspection frequencies outlined in the response applied to all structures within the scope of the Structures Monitoring Program or just concrete components. The staff discussed these issues with the applicant during a conference call on March 18, 2011. By letter dated May 10, 2012, the applicant confirmed that the spent fuel pool is an in-scope below-grade structure and would be inspected on a 5-year frequency and that the inspection frequencies outlined in the RAI response dated February 3, 2011, applied to all in-scope structures, regardless of the material. The staff finds the applicant's response acceptable because the applicant confirmed the spent fuel pool is an in-scope below-grade structure and would be inspected on a 5-year frequency and it outlined which structures are subject to a 5-year or 10-year inspection, and it aligned the frequency with that recommended in ACI-349.3R, which provides the basis for industry standards. In addition the applicant confirmed that the 5-year or 10-year inspection frequency based on ACI-349.3R applies to all structures within the scope of the Structures Monitoring Program. The staff's concern discussed in RAI B.2.1.31-5 is resolved.

Enhancement 1. LRA Section B.2.1.31 states an enhancement to "scope of program" that expands the scope of the Structures Monitoring Program to add the following:

- inspection of elastomeric materials, aluminum, non-metallic fire proofing, and Lubrite®
- inspection of overhead and fuel handling cranes, NUREG-0612 cranes, all supports, tanks (1-FP-TK-35-A, 1-FP-TK-35-B, 1-FP-TK-36-A, 1-FP-TK-36-B, and 1-FP-TK-29-A) and their supports and foundations, fire house boiler building, safety- and nonsafety-related electrical cable manhole and duct bank yard structures, and two fire protection water storage tanks
- opportunistic and focused inspections of below-grade and inaccessible concrete at least once every 5 years

The staff finds the addition of the above-listed materials, the cranes and support tanks, and inspections of opportunity for below-grade and inaccessible concrete to be an acceptable enhancement because, when implemented, the Structures Monitoring Program will address the materials and structures included within the scope of license renewal. These specific enhancements bring the "scope of program" program element of the applicant's Structures Monitoring Program into partial compliance with the "scope of program" program element provided in GALL Report AMP XI.S6, "Structures Monitoring Program."

However, it was also not clear to the staff how frequently the tanks within the scope of the applicant's Structures Monitoring Program would be inspected. By letter dated November 18, 2010, the staff issued RAI B.2.1.17-1 asking the applicant to verify whether the Structures Monitoring Program would also include inspection of tank coatings for tanks 1-FP-TK-35-A, 1-FP-TK-35-B, 1-FP-TK-36-A, 1-FP-TK-36-B, and 1-FP-TK-29-A. In its response dated December 17, 2010, the applicant stated that, in addition to monitoring the aging effects in the tanks, the program would also include inspection of the external surfaces of the aboveground tanks for cracking, flaking, or peeling of paint or coatings. After further review of the applicant's response, it was still not clear how often the applicant plans to visually inspect the tanks for cracking, flaking, or peeling of paint or coating(s) and whether it intends to follow the Structures Monitoring Program or the Aboveground Steel Tanks Program guidance, which recommends visual inspections at least every 2 years. The staff addressed this concern in a teleconference with the applicant on March 18, 2011.

In a supplemental response provided by letter dated April 14, 2011, the applicant further clarified RAI B.2.1.17-1 stating that the Structures Monitoring Program will perform external visual or tactile (where required) surface inspections every 5 years of the aboveground steel tanks 1-FP-TK-35-A, 1-FP-TK-35-B, 1-FP-TK-36-A, 1-FP-TK-36-B, and 1-AB-TK-29 (fire fuel oil, fire water, and auxiliary boiler fuel oil tanks) to address cracking, flaking, or peeling of paint, coatings, sealants, and caulking. Additionally, the Fire Protection Program will also visually inspect these tanks quarterly to assess the condition of their coatings. For tanks that have a caulking seal between the tank and the foundation, tactile examination will be performed to evaluate the condition of the caulking per the System Walkdown Engineering Guidelines.

The staff finds the applicant's response acceptable because the applicant will manage potential deterioration of the external surfaces of the aboveground tanks for cracking, flaking, or peeling of paint or coatings and, where applicable, the condition of caulking through two different AMPs—the Structures Monitoring Program and the Fire Protection Program. These two programs collectively will assure that the fire fuel oil tanks, fire water tanks, and auxiliary boiler fuel oil tanks external surfaces will be monitored so that the tanks can continue to perform adequately during the period of extended operation. The quarterly Fire Protection Program inspections also meet the frequency recommendation of every 2 years, as stated in the GALL Report AMP, Aboveground Steel Tanks Program. The staff's concerns described in RAI B.2.1.17-1 are resolved.

Enhancement 2. LRA Section B.2.1.31 states an enhancement to "parameters monitored or inspected" that expands the Structures Monitoring Program scope to include aging effects of elastomers for loss of sealing, leakage, and deterioration of seals; cracking of aluminum; abrasion and flaking of non-metallic fire proofing; corrosion, dirt, and distortion of Lubrite®; and degradation of below-grade concrete.

It was not clear to the staff, however, how the applicant will use visual inspections to detect degradations in elastomeric, aluminum, and non-metallic fire proofing materials before they lose their intended functions. The staff addressed this concern in a teleconference with the applicant on March 18, 2011.

In a supplemental response provided by letter dated April 14, 2011, the applicant stated that elastomeric roof material inspections will be done by a licensed professional roofing company. Every 5 years, the contractor will assess the condition of the roof elastomeric material for separation, environmental degradation, and water in-leakage due to weathering through physical roof walks and visual inspections. The applicant further stated that, for aluminum and non-metallic fire proofing materials, the applicant's inspectors are either licensed professional engineers experienced in this area or individuals working under the supervision of a licensed professional engineer with expertise in the design and inspection of steel, concrete, and masonry structures. During these inspections, aluminum will be visually inspected like all metallic materials (using the material aging effects) while non-metallic fire proofing, which is a sprayed on cementitious material, will be examined the same as concrete. The frequency of inspection is based on the environment, as articulated above. Harsh environments inspections will be performed every 5 years while those in mild environments will be every 10 years. The applicant, however, stated that operating experience may increase the frequency of these inspections. The applicant also stated that the acceptance criteria will be based on the engineering department standard for the Structures Monitoring Program, which describes the aging effects and evaluation criteria based on ACI 349 three-tiered hierarchy and quantitative limits. Finally, the applicant stated that upon further review of Table 3.5.2.4 in LRA Chapter 3, AMR item "Miscellaneous Yard Structures-Aluminum Station Blackout Structures Exposed To Air-Outdoor (External Weather)," was updated to reflect the appropriate aging effect for this component requiring management to be cracking instead of the originally reported crack initiation and crack growth.

The staff finds this enhancement and the clarifications provided by the applicant acceptable because inspections are performed periodically by professionals following the criteria laid-out in the Structures Monitoring Program. Furthermore, when implemented, this enhancement will support the aging effects for the component types to be monitored during the period of extended operation and will provide criteria for inspection of seals, aluminum, non-metallic fire proofing, Lubrite®, and below-grade concrete. These enhancements of the "parameters monitored or inspected" program element of the applicant's Structures Monitoring Program are consistent with the "parameters monitored or inspected" program element provided in GALL Report AMP XI.S6, "Structures Monitoring Program."

Enhancement 3. LRA Section B.2.1.31 states an enhancement to the "monitoring and trending" program element that expands the Structures Monitoring Program to perform below-grade inspections of buried concrete at least once every 5 years through either an opportunistic or focused inspection.

The staff finds this enhancement acceptable because, when implemented, this enhancement will add clarification to the component types to be monitored during the period of extended operation so that the extent of degradation of the buried concrete is such that reasonable assurance is provided that these components are capable of fulfilling their intended functions. These enhancements of the "monitoring and trending" program element of the applicant's Structures Monitoring Program are consistent with the "parameters monitored or inspected" program element provided in GALL Report AMP XI.S6, "Structures Monitoring Program."

Enhancement 4. LRA Section B.2.1.31 states an enhancement to the "detection of aging effects" program element that expands the Structures Monitoring Program to include one-time UT examinations of the two fire protection water storage tanks prior to the period of extended operation.

The staff finds this enhancement acceptable because it supports the Aboveground Steel Tanks AMP, and the inclusion of the examinations under the Structures Monitoring Program procedures is acceptable. A review of the technical acceptability of the one-time UT examination and its comparison to the GALL Report Aboveground Steel Tanks Program recommendations is discussed in the staff's review of the Aboveground Steel Tanks Program in SER Section 3.0.3.2.9.

Based on its onsite audit, the staff finds that elements one through six of the applicant's Structures Monitoring Program, which integrates the Masonry Wall Program and the Water Control Structures Inspection Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL Report AMPs XI.S5, XI.S6, and XI.S7. However, as discussed below, the staff has determined that the applicant needs to resolve Open Item OI 3.0.3.2.18-1 by enhancing program elements “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria,” of the Structures Monitoring AMP to demonstrate that the effects due to ASR will be adequately managed during the period of extended operation.

Operating Experience. LRA Section B.2.1.31 summarizes operating experience related to the Structures Monitoring Program and states that groundwater infiltration through below-grade concrete structures has been an issue at Seabrook. Groundwater sampling performed in November 2008 and September 2009 found pH values between 6.01–7.51, chloride levels between 19–3,900 ppm, and sulfate levels between 10-100 ppm, indicating that the groundwater is an aggressive environment. The LRA also states that below-grade concrete structures have experienced groundwater infiltration through cracks, capillaries, pore spaces, seismic isolation joints, and construction joints. To stop or reduce the infiltration, various methods have been used but have had only limited success (e.g., dewatering wells and waterproofing agents). The LRA further states that additional testing is planned during the second and third quarters of 2010 in areas that experienced groundwater infiltration to determine its aging effects and the need for additional remedial action. The LRA finally states that visual inspections have been conducted of nonsafety-related masonry for indications of cracking and degradation as identified in the “monitoring checklist” of the applicant’s Structures Monitoring Program. The condition of water control and flood protection structures has been assessed through visual inspections conducted through the applicant’s Structures Monitoring Program.

The staff reviewed the operating experience information, in the application and during the onsite audit, to determine if 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 plant operating experience information to determine if the applicant adequately incorporated and evaluated operating experience related to this program.

During its review, the staff identified operating experience that could indicate that the applicant’s program may not be effective in adequately managing aging effects during the period of extended operation. The staff determined the need for additional clarification that resulted in the issuance of four RAIs.

During the audit walkdown and review of condition reports, the staff noted that groundwater infiltration through below-grade concrete walls has been a chronic issue at the plant. The staff also observed indications of leaching and alkali-aggregate reactions occurring in the concrete exposed to groundwater infiltration. The staff was unclear if the concrete degradation due to groundwater infiltration had been quantified and how the degradation will be managed during the period of extended operation. To address the groundwater issue, by letter dated November 18, 2010, the staff issued RAI B.2.1.31-1 expressing concerns on the effects of its infiltration in the concrete structures and requesting the applicant to provide a summary of all concrete mechanical testing performed to date and explain how its results are correlated to the actual plant structures. The staff also asked the applicant to provide the root cause of any reductions in structural capacities and degraded material properties and explain how the followup aging effects would be managed during the period of extended operation.

In its response dated December 17, 2010, the applicant stated that concrete mechanical testing, performed in May of 2010, is only reflective of the location where it was conducted. Specifically, the applicant stated that cores were taken and penetration resistance tests (PRT) were conducted to evaluate the compressive strength of concrete, at elevation -20 ft of the “B" Electrical Tunnel. The average compressive strength for the PRT was 5,340 psi and, for the bores, 4,790 psi. The measured strength was approximately 20 percent less than that obtained in earlier years. In particular, the PRT performed in 1979 yielded a compressive strength of 6,759 psi. For the construction test cylinders tested in 1975, the compressive strength was 6,120 psi. Similarly, analysis of current data indicated a reduction in the original modulus of elasticity by about 47 percent. Further, petrographic analysis of the 2010 core samples showed evidence of ASR. The applicant further stated that a prompt operability determination concluded that the areas of concrete on the “B” electrical tunnel affected by ASR comply with the applicable design codes, and the structural integrity of the “B” electrical tunnel is intact with all SSCs housed within the tunnel being operable and capable of performing their design functions. The applicant finally stated that an extent of condition investigation is in progress to test potentially five additional suspect areas (including the containment enclosure building) to obtain supplementary information for the assessment of the plant concrete condition and the cause of its degradation. The Structures Monitoring Program has recognized ACI 349 as a monitoring and inspection standard that will help manage aging effects during the period of extended operation. Identified deficiencies will be evaluated and put into the Corrective Action Program for resolution (i.e., remediation, corrective, and preventive actions) as required, including further structural analysis, if necessary.

After review of the applicant’s response, the staff did not understand what the extent of condition assessment would include and how it would ensure the adequacy of susceptible concrete during the period of extended operation. The response also lacked information regarding approximate completion dates and a probable path forward including the location and timing of future tests and proposed remedial actions. Therefore, by letter dated March 17, 2011, the staff issued a followup RAI to RAI B.2.1.31-1 asking the applicant to identify the extent and timeliness of the assessment and anticipated remediation, including the path forward to ensure the concrete would retain its integrity during the period of extended operation.

By letter dated April 14, 2011, the applicant responded to the RAI. In the response, the applicant stated that concrete samples had been taken from five additional locations, which were chosen because they exhibited groundwater in-leakage and surface cracking indicative of ASR. The applicant further explained that an action plan was being developed to address the ASR degradation. The plan would include multiple activities to include those listed below:

- identify areas potentially susceptible to ASR
- complete concrete testing in other susceptible areas to determine compressive strength, modulus of elasticity, and confirm the presence of ASR
- based on test results, reconcile existing calculations and analyses to ensure structures continue to meet all design basis conditions
- perform lab tests to determine the rate of the ASR degradation mechanism and how it propagates
- issue an engineering evaluation addressing ASR, the results of testing, and mitigation techniques
- update the Structures Monitoring Program to include guidance on monitoring for ASR, including the appropriate frequency of inspection
- develop a long-range plan to implement mitigation techniques to arrest ASR degradation

The applicant further stated that the implementation of the action plan is tentatively scheduled to be completed in December 2013. Finally, the applicant stated that the Structures Monitoring Program will be revised to include action for inspection and monitoring of concrete for degradation due to ASR.

The staff reviewed the applicant's response and finds the response lacked specific information about what tests (laboratory and in-situ) would be conducted and when. The response also made no mention of how possible reductions in concrete shear strength were being estimated and addressed. In addition, the RAI response stated that cores were being taken in accordance with American Concrete Institute (ACI) 228.1R-03; however, it did not address the statistical validity and size of core samples taken or planned at each location. Therefore, by letter dated June 29, 2011, the staff issued follow up RAI B.2.1.31-1 requesting the applicant to:

1) Explain if the current operability evaluation remains valid until the long-term aging management plan is developed and implemented.
2) Explain how the concrete tests and evaluations performed so far can be used to establish a trend in degradation of the affected structures until the long-term aging management plan is implemented.
3) Provide detailed and comprehensive information regarding the planned approach to addressing ASR degradation throughout the site.
4) Explain how the possibility of a reduction in shear strength capacity due to ASR degradation is being evaluated.

By letter dated August 11, 2011, the applicant provided initial response to the RAI. In this response, the applicant stated that the current operability determination is expected to remain valid but may require modification. The applicant also stated that a comprehensive plan to evaluate and address ASR concrete degradation, and develop and implement a long-term monitoring plan is ongoing and will be included in an engineering evaluation scheduled to be completed by March 2012.

In a subsequent letter dated March 30, 2012, the applicant stated that it has initiated actions to perform additional testing to demonstrate that the effects of ASR on in-scope structures can be managed to maintain the intended functions of the affected structures through the period of extended operation. The applicant also stated that through this testing, quantitative crack limits will be developed. The crack limits will be incorporated into the Structural Monitoring Program to manage the effects of ASR on concrete structures. The quantitative crack limits will be used to develop acceptance criteria such that corrective action can be implemented prior to loss of intended function. The applicant also submitted another letter on April 18, 2012, in which it stated that the two operability evaluations were revised on October 11, 2011. These revised operability evaluations concluded that the ASR affected structures are fully capable of performing their intended function and operable with reduced margin. The applicant further stated that full qualification will be attained when the testing and analysis plans are completed and the long-term resolution is incorporated into the UFSAR and/or other applicable design documents.

The staff reviewed the applicant's response in the three letters and noted that the applicant plans to enhance the Structural Monitoring Program to manage ASR degradation. However, the enhancements will not be completed until the long-term additional testing is completed and quantitative acceptance criteria for crack limits are developed. The staff is concerned that the applicant has not provided the details of the proposed enhancements to the program elements “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria,” to the Structures Monitoring AMP to manage the effects of ASR. A revised aging management program with enhancements for managing the ASR degradation, for each in-scope concrete structure, is required to demonstrate that the effects of aging will be maintained consistent with the current licensing basis for the period of extended operation as mandated by 10 CFR 54.21(a)(3). Until the applicant provides an enhanced Structures Monitoring Program, this issue is Open Item OI 3.0.3.2.18-1.

During the audit walkdown and review of condition reports, the staff also noted that groundwater infiltration has caused degradation of internal plant structures and components, such as supports, base-plates, cable trays, etc. The staff was unclear how the degradation due to groundwater infiltration will be managed during the period of extended operation. To address this issue, by letter dated November 18, 2010, the staff issued RAI B.2.1.31-2 asking the applicant to explain how internal plant structures exposed to groundwater infiltration will be managed for additional or accelerated degradation during the period of extended operation.

In its response, dated December 17, 2010, the applicant reiterated that components affected by groundwater in-leakage are managed through the plant's Structures Monitoring Program, which follows the Structural Engineering Standard Technical Procedure issued in March of 2010. The Structures Monitoring Program inspects building structural steel components (e.g., base plates, columns, beams, braces, platforms, cable trays, structural bolting, and fasteners) for corrosion, peeling paint, excessive support deflections, twisting, warping, or locally deflecting beams and columns, loose or missing anchors and fasteners, missing, cracked, or degraded grout under the steel base plates, and cracked welds. The program evaluates and assesses each component’s acceptability based on the extent of its degradations and then initiates corrective actions, followed by additional inspections to verify their effectiveness.

After review of the applicant’s response, it was not clear to the staff why, after the update of the procedure in March of 2010, there was still degradation due to in-leakage witnessed during audit walkdowns in October of 2010. To this end, by letter dated March 17, 2011, the staff issued a followup RAI to RAI B.2.1.31-2 asking the applicant to state what actions will be taken to avert further degradation in areas prone to in-leakage.

By letter dated April 14, 2011, the applicant responded to the RAI and stated that deficiencies identified in structural steel during structures monitoring inspection are documented on the inspection reports and evaluated. The applicant further stated that deficiencies that do not meet the acceptance criteria are entered into the Corrective Action Program, and deficiencies that are accepted by engineering review are trended for evidence of further degradation. The applicant also explained that deficiencies being repaired or trended are subject to follow-up inspections at a maximum frequency of 2.5 years. The applicant also stated that the structures monitoring procedure has been revised to include specific direction regarding monitoring for the presence of water in-leakage.

The staff reviewed the applicant’s response and finds it acceptable because the applicant explained that deficiencies are either repaired or accepted by engineering review. If a condition is accepted by engineering review, the inspection frequency is adjusted accordingly to provide assurance that any further degradation will be properly identified and addressed (e.g., maximum inspection frequency of 2.5 years). This approach is consistent with recommendations in the GALL Report AMP XI.S6 which recommends that aging effects are evaluated by qualified personnel using criteria derived from industry codes and standards contained in the plant current licensing bases, including ACI 349.3R. As recommended in ACI 349.3R, the applicant’s inspectors for the Structures Monitoring Program are either licensed professional engineers or individuals working under the supervision of a licensed professional engineer with expertise in the design and inspection of steel, concrete, and masonry structures. These inspectors are qualified and will adjust the inspection frequency depending on the results of the inspection but not more than 2.5 years for structural steel components in the areas of ground water in-leakage. This is consistent with the guidance in ACI 349.3R that recommends increase in frequency of inspection for structures that are found to be degraded beyond acceptance criteria. The staff's concerns described in RAI B.2.1.31-2 and its followup RAI are resolved.

During the audit walkdown and review of condition reports, the staff further noted that groundwater infiltration through below-grade concrete walls has been a chronic issue at the plant; however, the staff was unable to locate any inspection reports that identified and monitored and trended the degradation caused by the infiltration in a quantitative manner. The staff concluded that a baseline quantitative concrete inspection of in-scope structures is necessary for monitoring and trending degradation during the period of extended operation. To address this issue, by letter dated November 18, 2010, the staff issued RAI B.2.1.31-3 requesting that the applicant discuss plans for conducting a quantitative baseline inspection, in accordance with ACI 349.3R, prior to the period of extended operation.

In its response, dated December 17, 2010, the applicant stated that the Structures Monitoring Program described in LRA Appendix A, Section A.2.1.31, and LRA Appendix B, Section B.2.1.31, has been revised to include the ACI 349.3R guidance for inspections. This is reflected in Supplement 2 of the Seabrook LRA, dated November 15, 2010. The implementing procedure for the Structures Monitoring Program issued in March of 2010 describes the evaluation criteria based on the ACI 349.3R three-tiered hierarchy and quantitative limits.

The staff reviewed the applicant's response and finds it acceptable because its program is upgraded to follow the industry defined three-tiered ACI 349.3R hierarchical standard (i.e., acceptance without further evaluation, acceptance after review, conditions requiring further evaluation) with quantitative limits. In addition, the new acceptance criteria have already been implemented and are being used during current structural inspections. The staff's concerns described in RAI B.2.1.31-3 are resolved.

During the audit and review of program basis documents, the staff noted that the fuel transfer canal has shown indications of borated water leakage. In order to complete its review, the staff requested additional information on historic and current leakages (values, paths, etc.) and the condition of the affected structures. To address this issue, by letter dated November 18, 2010, the staff issued RAI B.2.1.31-4 requesting the applicant to discuss the leakage path, current status of leak(s), and any other information to demonstrate that the affected structures will be able to perform their intended functions during the period of extended operation.

In its response dated December 17, 2010, the applicant itemized historical records dating back to 1999. During that year, the applicant performed a root cause study, which identified the source of water in the annulus region between the containment building and the containment enclosure building to have originated from the spent fuel pool. Immediately, an enclosed tank was installed in the spent fuel pool leakoff sump to collect new leakage and to protect the sump and the environment from further contamination. Additional actions included protecting foundations and groundwater from contamination with selective dewatering through existing wells and removing leakage from contaminated systems. From 2000–2004, testing and inspection continued in the spent fuel pool, the spent fuel transfer canal, and the cask handling area to identify the source of the leak. In 2002, the applicant installed a nonmetallic liner in an attempt to stop the leakage. The applicant further stated that, by 2004, the leak had stopped in the spent fuel pool (confirmed by the lack of contaminated water in the sump), but water level fluctuations caused the leak in the canal to increase to 350 gallons per day. From 2005–2008, the applicant repaired delaminating coatings, and since 2006, the applicant instituted programmatic weekly monitoring of the leakage. A 2002 and 2004 chemical analysis of leakage indicated that it is compatible to the water in the spent fuel pool.

After review of the applicant's response, it was not clear to the staff whether the applicant has stopped all the leakage and that no through-wall leakage is occurring. In addition, based on industry operating experience with failures of spent fuel pool nonmetallic coatings, the staff is not confident that the nonmetallic liner is an appropriate long-term fix. To address these issues, by letter dated March 17, 2011, the staff issued a follow-up RAI to B.2.1.31-4 requesting that the applicant discuss the measures to be taken to demonstrate the integrity of the concrete structures exposed to spent fuel pool leakage, including the possibility of core bores from known leakage locations. The staff also requested that the applicant explain its conclusion that no through-wall leakage is occurring at the present, especially in inaccessible areas. Furthermore, the staff asked the applicant to demonstrate that, if a nonmetallic liner is relied upon to stop leakage, what measures will be taken to ensure its adequacy during the period of extended operation.

By letter dated April 14, 2011, the applicant responded to the RAI and stated that a core-bore test would be completed no later than December 31, 2015. The test would take place in an area subjected to wetting during the timeframe of the leakage and would test for compression strength of the concrete and would expose rebar. The applicant further stated that the spent fuel pool leak-off system is routinely hydro-lazed to ensure that it is free-flowing. The applicant stated that the leak-off system is the path of least resistance for any water between the liner plate and the concrete wall, and leakage from the spent fuel pool would drain to the leak collection sump. The sump is periodically sampled and tested for signs of leakage, such as boron and tritium. Finally, the applicant stated that the nonmetallic lining is replaced on the basis of condition monitoring that will identify when the end of life for the material has been reached. The applicant stated that the following activities will be continued during the period of extended operation:

- monitoring of the liner coating coupon system under the Preventative Maintenance (PM), "Visual Inspection of Coupons Coated with SEFR"
- continued sampling and analysis of leak system effluent under procedure "Spent Fuel Pool Leakage Collection Program"

The staff reviewed the applicant's response but found the response was unclear in identifying where the leakage was coming from and what the leakage values had been historically. In addition, the applicant did not identify how frequently the leak-off system was confirmed to be clear. To clarify these points, the staff held a conference call with the applicant on May 31, 2011. During the conference call, the applicant stated that additional spent fuel pool leakage was detected during the spring 2011 outage. Therefore, to address this additional operating experience, by letter dated June 29, 2011, the staff issued followup RAI B.2.1.31-4 requesting the applicant:

(1) Provide technical justification for the adequacy of the December 31, 2015, deadline for the spent fuel pool concrete core bore, or provide a new deadline and appropriate justification.

(2) Identify the frequency that the leak-off system is ensured to be free-flowing.

(3) Provide information on the recent leakage from the spent fuel pool, including the probable leakage path and source; whether the leakage is contained within the leak-off system; and whether or not chemical analysis will be performed on leakage during the period of extended operation.

By letter dated August 11, 2011, the applicant responded to the first request by stating that there is not continuous borated water leakage from the spent fuel pool. Currently, any leakage collects in a catch basin in sump and does not contact concrete. The applicant further committed to confirming the absence of embedded steel corrosion by performing a shallow core sample in an area subjected to wetting during the time frame of the spent fuel pool leakage. Finally, the applicant stated that the December 31, 2015, deadline was acceptable because similar operating experience at other nuclear plants has shown that structural capacity is not significantly affected by exposure to borated water.

In response to the second request, the applicant stated that hydro-lazing is performed on the spent fuel pool leak-off lines at a 4.5-year frequency, which will be maintained throughout the period of extended operation. The applicant also explained that leak-off is recorded once a month and reviewed by the system engineer. Unusual leakage, or lack thereof, could be an indicator of blockage and would be investigated accordingly.

In response to the third request, the applicant stated that the spent fuel pool leak-off is analyzed for gamma and tritium activity. On April 6, 2011, zone 6 of the spent fuel pool leak-off system showed a step increase in the tritium activity concentration. The applicant explained that this increase occurred coincident with refilling of the cask loading pool, which had previously been drained. At this point, the leak rate was estimated at 1.2 gal. per day (gpd). Subsequent measurements identified a peak leak rate of approximately 2.57 gpd, which decreased to the current level of 0.016 gpd (approximately 2 oz per day). The applicant further explained that, on average, approximately 10 gallons per day of groundwater infiltration leaks out of the zone 6 tell-tale line. The applicant explained that "[t]he volume of spent fuel pool leakage is estimated by taking the ratio of the leak-off line tritium concentration to the pool tritium concentration and multiplying that value by the amount of zone 6 leakage pumped out from the collection tank. In this particular instance, the only leak-off line that indicated any leakage was zone 6." The applicant then stated that there are several potential causes for the increased leakage, including a new stainless steel liner plate leak in an area not coated with the non-metallic liner; a failure in the non-metallic liner at the same location as a stainless steel liner failure; or a skimmer pit leak. The applicant further stated that these possibilities are being addressed with corrective actions, including verifying the integrity of the cask loading area liner through drain down and inspection, revising procedures for cask filling to limit the pool level, and determining if the current design of the skimmer pits is appropriate or if changes can be made to prevent leakage from the pit. Finally, the applicant committed to analyze spent fuel pool leak-off for chlorides, sulfates, pH and iron for four quarters of 1 year once every 5 years.

The staff reviewed the applicant's response and was unable to determine the source or flow path of the leakage. In response to the first portion of the followup RAI, the applicant stated that it "does not have continuous borated water leakage from the spent fuel pool"; however, in response to the third portion, the applicant stated "leakage decreased to the current level of 0.016 gpd." Based on this response, it is not clear if the spent fuel pool is leaking. The staff also noted that the applicant committed to monitor the leakage quarterly for chlorides, sulfates, pH, and iron once every 5 years (Commitment No. 68). This approach is unacceptable for detecting a possible trend that may indicate degradation such as an increase in the iron content of the leakage. The staff provided its concerns to the applicant during an inspection visit the week of September 26, 2011.

To address these concerns, the applicant supplemented its response to followup RAI B.2.1.31-4 by letter dated November 2, 2011. In its response, the applicant explained that the spent fuel pool, cask handling, and fuel transfer canal areas have nine zones that collect leakage. The spent fuel pool is separated from the cask handling area and the fuel transfer area by a gate. The applicant stated that there have been no incidents of leakage from the spent fuel pool; the only incidents of leakage have been from the cask handling and fuel transfer canal areas. The applicant further stated that zone 6 is the only leakage collection sample line that routinely has water flow, that this zone collects leakage from the cask handling area, and that the majority of the water in the zone 6 sample line is from groundwater in-leakage. The applicant further clarified that the leakage detected on April 6, 2011, was from zone 6, which meant it was from the cask handling area and not the spent fuel pool. The applicant also updated Commitment No. 68 to sample the leak-off water once every 3 months.

The staff reviewed the applicant's supplement and noted that leakage has not occurred from the spent fuel pool; all historic leakage has been from the cask handling and fuel transfer canal areas. The staff also noted that the applicant plans to sample the leak-off water quarterly, which provides reasonable assurance any negative trends in chlorides, sulfates, pH, or iron content that could indicate degradation would be captured in a timely fashion. The staff also reviewed the original RAI and followups dated December 17, 2010, April 14, 2011, and August 11, 2011, and noted that the current leakage is captured within the leak-off system and is collected in the spent fuel pool leakage sump. The staff further noted that there has been no operating experience with leakage migrating through the concrete walls, except the leakage identified in 1999, which was leakage out of the sump that had been directed to the sump by the leak-off collection system. Once the spent fuel pool leakage sump was identified as the source of the through-wall leakage, a tank was added to the sump, which collects any leak-off flow before it potentially contaminates the sump. The staff also noted that, in order to keep the leak-off system free-flowing, the applicant will hydro-laze the lines on a 4.5-year frequency and monitor the flow monthly for any indications of blockage. Finally, the staff noted that the applicant committed to take a core bore from the spent fuel pool sump in an area that was exposed to through-wall leakage (Commitment No. 67). The bore will be examined for concrete degradation and will expose the rebar to examine it for any signs of degradation. Based on its review, the staff finds the applicant's response and approach acceptable for the following reasons:

- The applicant has plans in place to take a core bore from an area that was continuously wetted by borated water. This provides assurance that any degradation that may have occurred in the past will be identified and addressed prior to the period of extended operation.
- The applicant does not currently have any indications of leakage migrating through the concrete walls of the spent fuel pool (i.e., leakage not captured in the leak-off system). This provides assurance that any degradation that may have occurred in the past due to borated water will not continue during the period of extended operation.
- The applicant has plans in place to maintain the leak-off system clear of blockage, which provides assurance that any future leakage will be captured in the system and directed to the sump, as opposed to migrating through the spent fuel pool concrete walls.

- The applicant will monitor the chemical properties of the leak-off collection on a quarterly basis. Any changes in the chemical makeup of the leak-off water could be a sign that the leakage is interacting with the concrete, which may indicate leakage outside of the collection system.
- The applicant will continue to attempt to locate the leakage source and stop it completely.

Based on the above, the staff's concern discussed in RAI B.2.1.31-4, and the associated followup RAIs, is resolved.

Until Open Item OI 3.0.3.2.18-1 concerning the enhancement to the Structures Monitoring AMP to manage the effects of ASR is resolved, the staff cannot find that the 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.

<u>UFSAR Supplement</u>. LRA Sections A.2.1.31 provides the UFSAR supplement for the Structures Monitoring Program.

In LRA Section Appendix A, the applicant provided the UFSAR supplement for the Structures Monitoring Program. The staff reviewed this UFSAR supplement section and noted that it conforms to the recommended description for these types of programs, as described in SRP-LR Table 3.5-2. However, the supplement made no mention of ACI 349.3R, which is an important reference document for the applicant's program. Several of the applicant's program elements were found consistent with the GALL Report recommendations because they followed guidance from ACI 349.3R. This information was provided to the applicant during the consistency audit. To address the issue, by letter dated November 15, 2010, the applicant revised the supplement to include ACI 349.3R. The staff also noted that the applicant committed (Commitment Nos. 32 and 33) to enhance the Structures Monitoring Program prior to entering the period of extended operation. Specifically, the applicant committed to do the following:

- enhance procedure to add the aging effects, additional locations, inspection frequency, and ultrasonic test requirements
- enhance the procedure to include inspection of opportunity when planning excavation work that would expose inaccessible concrete

In addition, the applicant committed (Commitment Nos. 67 and 68) to do the following:

- perform one shallow core bore in an area that was continuously wetted from borated water to be examined for concrete degradation and also exposed rebar to detect any degradation such as loss of material, no later than December 31, 2015.
- perform sampling at the leakoff collection points for chlorides, sulfates, pH, and iron once every three months, starting January 2014.

Additional enhancements to the structures monitoring aging management program are required to closeout Open Item OI 3.0.3.2.18-1 for the ASR issue. The staff finds that until Open Item OI 3.0.3.2.18-1 is resolved, the information in the UFSAR supplement, as required by 10 CFR 54.21(d) is not adequate.

Conclusion. The staff concludes that the applicant has not 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 applicant needs to resolve the Open Item OI 3.0.3.2.18-1, as discussed above. Once the Open Item OI 3.0.3.2.18-1, as discussed above is resolved, the applicant will need to make appropriate changes to the UFSAR supplement for this AMP to include a complete summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.19 Inaccessible Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Program

Summary of Technical Information in the Application. LRA Section B.2.1.34, as revised by LRA supplement letters dated October 29, 2010, and December 17, 2010, describes the new Inaccessible Power Cables Not Subject To 10 CFR 50.49 EQ Requirements Program as consistent, with an enhancement, with GALL Report AMP XI.E3, "Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements." The applicant stated that the new program will manage the aging effects of localized damage and breakdown of insulation leading to electrical failure of inaccessible power cables (greater than or equal to 400 V) due to adverse localized environments caused by exposure to significant moisture regardless of frequency of energization. The applicant also stated that an adverse localized environment for inaccessible power cables is defined as periodic exposures to moisture that lasts more than a few days (e.g., cable in standing water). The applicant further stated that the applicant's Inaccessible Power Cables Not Subject To 10 CFR 50.49 EQ Requirements Program includes periodic and event-driven inspection of manholes containing in-scope inaccessible power cables and draining water, as needed. The applicant stated that the maximum time between inspections will be no more than 1 year, but the frequency will be based on plant-specific operating experience with cable wetting or submergence, with the first inspections completed prior to the period of extended operation. In addition, the applicant stated that in-scope inaccessible power cables are tested to provide an indication of the condition of the conductor insulation with testing performed prior to the period of extended operation and at least every 6 years thereafter.

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 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 Report AMP XI.E3. As discussed in the audit report, the staff confirmed that these elements are consistent with the corresponding elements of GALL Report AMP XI.E3.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements associated with the enhancement to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement 1. During the audit, the staff was concerned that the applicant's AMP may not be consistent with GALL Report AMP XI.E3 or SRP-LR Section A.1.2.3.10 in that, as additional operating experience is obtained, lessons learned are evaluated and the program adjusted as required. Specifically, the application of GALL Report AMP XI.E3 to inaccessible medium voltage cable was based on operating experience available at the time Revision 1 of the GALL Report was developed. Recently identified industry operating experience indicates that the presence of water or moisture can be a contributing factor in inaccessible power cable failures at lower service voltages (400 V to 2 kv). Further, industry operating experience, provided by NRC applicants in response to GL 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," has shown that there is an increasing trend of cable failures with length in service beginning in the 6th through 10th years of operation and that moisture intrusion is a predominant factor contributing to cable failure. Industry operating experience has also shown that some NRC applicants may experience events, such as flooding or heavy rain, that subjects cables within the scope of program for GALL Report AMP XI.E3 to significant moisture.

In response to the staff's concern, the applicant stated during the audit that the Inaccessible Power Cables Not Subject To 10 CFR 50.49 EQ Requirements Program and associated UFSAR supplement would be revised to address the staff concerns regarding more recent industry operating experience.

The applicant revised LRA Section B.2.1.34 by letters dated October 29, 2010, and December 17, 2010, which provided an enhancement to "scope of program," "parameters monitored or inspected," and "detection of aging effects." The enhancement expanded the Inaccessible Power Cables Not Subject To 10 CFR 50.49 EQ Requirements Program to include all inaccessible power cables (including de-energized cable) greater than or equal to 400 V within the scope of license renewal and subject to significant moisture. In addition, although not specifically identified as an enhancement or exception, the applicant also revised the cable manhole inspection frequency from a maximum time between inspections of no more than 2 years to no more than 1 year. In addition to periodic inspections, the applicant also revised the LRA to include inspections for event-driven occurrences (e.g., rain or flood). The applicant also revised the cable testing frequency from at least every 10 years to at least every 6 years.

The staff finds that, with the enhancements and revised inspection and testing intervals specified in the LRA supplements dated October 29, 2010, and December 17, 2010, there is reasonable assurance that the applicant's Inaccessible Power Cables Not Subject To 10 CFR 50.49 EQ Requirements Program will adequately manage the aging effects of inaccessible power cables. The applicant's program addresses industry operating experience consistent with current staff and SRP-LR Section A.1.2.3.10 guidance. The staff concerns identified in the audit report are resolved.

Based on its audit, and review of the applicant's LRA including supplements dated October 29, 2010, and December 17, 2010, the staff finds that elements one through six of the applicant's Inaccessible Power Cables Not Subject To 10 CFR 50.49 EQ Requirements Program, with acceptable enhancement, are consistent with the corresponding program elements of GALL Report AMP XI.E3 and industry operating experience.

Operating Experience. LRA Section B.2.1.34 as revised by LRA supplement dated October 29, 2010, summarizes operating experience related to the Inaccessible Power Cables Not Subject To 10 CFR 50.49 EQ Requirements Program.

The applicant stated that the GALL Report was considered as part of its operating experience review through the September 2005 issue date of GALL Report, Revision 1. In its response to GL 2007-01, the applicant concluded that no failures have occurred in power cables within the scope of the maintenance rule. The applicant also noted that, based on operating experience, it has maintained an inspection of 10 percent of the safety-related manholes every 5 years since 1994. The applicant also stated that a 2009 fleet procedure was issued that provided dewatering for electrical cables with the strategy that all cables important to generation and nuclear safety are to be maintained in a dry (not submerged) condition. The applicant further stated that it is in the process of implementing this fleet procedure. The applicant stated that it performed inspections in late 2009 and early 2010 of all safety-related manholes and removed water from the manholes. The applicant further stated that the inspection frequency was increased to prevent submergence of safety-related cables and that it has performed tests on all safety-related, inaccessible, in-scope, greater than or equal to 400 V power cables and the nonsafety-related medium voltage cables with the test acceptance criteria met.

The staff reviewed the operating experience, in the application and during the audit, to determine if 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 plant operating experience including manhole inspection and cable test information to determine if the applicant adequately incorporated and evaluated operating experience related to this program. Further, the staff performed a search of regulatory operating experience for the past 10 years through April 2010. Databases were searched using various key word searches and then reviewed by technical auditor staff. The staff walked down selected in-scope manholes during the audit and noted limited water accumulation with no cable submergence noted.

During the audit, the staff identified industry 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. The staff determined the need for additional clarification concerning more recent industry operating experience. To resolve the staff’s concerns, the applicant provided LRA supplements dated October 29, 2010, and December 17, 2010, which included an enhancement of the Inaccessible Power Cables Not Subject To 10 CFR 50.49 EQ Requirements Program. The enhancement increased the scope of the program to include in-scope inaccessible cable greater than or equal to 400 V (energized or deenergized) subject to significant moisture. Additional program revisions included increasing the manhole inspection frequency to a maximum time between inspections of 1 year and changing the cable testing frequency to at least once every 6 years. To account for event-driven occurrences such as heavy rain or flooding, the applicant also included event-driven inspections for cable manholes. With the included enhancement and additional changes to the applicant’s Inaccessible Power Cables Not Subject To 10 CFR 50.49 EQ Requirements Program, the applicant’s program is consistent with recent industry- and plant-specific operating experience and current staff guidance. The staff concerns identified during the audit are resolved.

Based on its audit, review of the application, and review of the applicant’s LRA supplements dated October 29, 2010, and December 17, 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 and that implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the “operating experience” program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.34 provides the UFSAR supplement for the Inaccessible Power Cables Not Subject To 10 CFR 50.49 EQ Requirements Program.

The staff reviewed the UFSAR supplement description of the program, as revised by letters dated October 29, 2010, and December 17, 2010, and noted that it conforms to the recommended description for this type of program, as described in SRP-LR Table 3.6-2. As part of the applicant's LRA supplements, the applicant revised LRA Section A.2.1.34 to do the following:

- add in-scope low-voltage power cable (greater than or equal to 400 V)
- eliminate the criterion that exempts cables when not energized 25 percent of the time
- revise inspections and test frequencies
- include event-driven inspections due to event-driven occurrences such as heavy rain or flooding

The staff also noted that the applicant committed (Commitment No. 36) to implement the new Inaccessible Power Cables Not Subject To 10 CFR 50.49 EQ Requirements Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determined 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).

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Inaccessible Power Cables Not Subject To 10 CFR 50.49 EQ Requirements Program, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Additionally, the staff finds the program's enhancement to incorporate greater than or equal to 400 V in-scope inaccessible power cable to be consistent with industry operating experience. The staff concludes that the applicant 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).

3.0.3.2.20 Protective Coating Monitoring and Maintenance Program

<u>Summary of Technical Information in the Application</u>. By letter dated November 15, 2010, the applicant submitted an LRA supplement that included LRA Section B.2.1.38 which describes the existing Protective Coating Monitoring and Maintenance Program as consistent, with enhancements, with GALL Report AMP XI.S8, "Protective Coating Monitoring and Maintenance Program." The applicant stated that the program manages cracking, blistering, flaking, peeling, and delamination of the Service Level 1 coatings, consistent with the guidelines of Regulatory Position C4 of the NRC RG 1.54, Revision 1, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants," as described in NUREG-1801, Revision 1.

The applicant stated that, at the beginning of every refueling outage (RFO), the NextEra Energy coating supervisor and the design engineer inspect all areas and components from which peeling coatings have the potential of falling into the reactor cavity or emergency core cooling system (ECCS) recirculation sumps. It was indicated that after completion of all containment closeout work, the coating supervisor shall notify the design engineer and the nuclear coating specialist to perform the containment closeout inspection, and unqualified coatings found during this inspection shall be evaluated based on size, location, and coating type. The applicant further stated that, based on the results of this evaluation, the unqualified coating shall be removed as directed by the design engineer or documented on the containment coatings closeout inspection form and on an action request.

The applicant stated that the program requires that all accessible areas of containment receive a coatings inspection of all Service Level 1 coatings. It was reported that these inspections are performed during each RFO by qualified coatings inspectors. The applicant stated that the coatings inspectors are qualified per the requirements of ANSI N45.2.6, “Qualification of Inspection, Examination, and Testing Personnel.”

The applicant stated that the coatings used in Service Level 1 applications were qualified and applied in accordance with the requirements of the following documents:

- NRC RG 1.54
- ANSI N101.4-1972, “Quality Assurance for Protective Coatings Applied to Nuclear Facilities”
- ANSI N101.2-1972, “Protective Coatings (Paints) for Light Water Nuclear Containment Facilities”
- ANSI N512-1974, “Protective Coatings (Paints) for the Nuclear Industry”

The applicant indicated that the determination of acceptability of the coatings will be made by qualified inspection personnel. The applicant reported that the inspection personnel determination, as well as any deteriorated or unqualified coatings identified, will be documented in the as-left action request.

Staff Evaluation. During its audit, the staff reviewed the applicant’s Service Level 1 coatings qualification. The staff also reviewed the plant conditions to determine if they are bounded by the conditions for which the GALL Report was evaluated.

The staff evaluated the information provided by the applicant and determined that the application of the Protective Coatings Monitoring and Maintenance Program is acceptable in managing coating degradation since the program is consistent with GALL Report Section XI.S8. The staff finds the frequency of coating inspections to be acceptable since inspecting every RFO would provide adequate assurance that there is proper maintenance of the protective coatings. The method of performing the coatings inspection is acceptable since the staff has found acceptable that visual inspections are performed and are able to detect for adverse coating conditions such as blistering, cracking, flaking, rusting, checking, insufficient adhesion, undercutting, peeling, and other signs of distress. The staff also found acceptable the manner in which the programs meet the requirements of ANSI N101.4-1972, N101.2-1972, N512-1974, since it is consistent with NRC RG 1.54. In addition, the qualification of personnel who perform the inspection is found to be acceptable since the staff has reviewed and confirmed that ANSI N45.2.6 is acceptable.

The staff also reviewed the portions of the “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements associated with enhancements to determine if 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.2.1.38 states an enhancement to the “detection of aging effects” program element. The applicant stated that the program will be enhanced by designating and qualifying an inspection coordinator and an inspection results evaluator.

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 of GALL Report AMP XI.S8.

Enhancement 2. LRA Section B.2.1.38 states an enhancement to the “detection of aging effects” program element. The applicant stated that the program will be enhanced to include instruments and equipment needed for inspection (i.e., flashlight, spotlights, marker pen, mirror, measuring tape, magnifier, binoculars, camera with or without wide angle lens, self sealing polyethylene sample bags).

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 of GALL Report AMP XI.S8.

Enhancement 3. LRA Section B.2.1.38 states an enhancement to the “monitoring and trending,” program element. The applicant stated that the program will be enhanced to include a review of the previous two monitoring reports.

The staff notes that the frequency of monitoring reports are completed during the coating inspections every RFO and would provide adequate assurance that the protective coatings are being trended for degradation. The method of performing the coatings inspection, as described above, is to do visual inspections which detect for adverse coating conditions such as blistering, cracking, flaking, rusting, checking, insufficient adhesion, undercutting, peeling, and other signs of distress.

On the basis of its review, the staff finds this enhancement acceptable because it is consistent with ASTM D 5163 which specifies a review of the previous two monitoring reports (two previous RFOs) and when the enhancement is implemented, prior to the period of extended operation, it will make the program consistent with the recommendations in GALL Report AMP XI.S8.

Enhancement 4. LRA Section B.2.1.38 states an enhancement to the “acceptance criteria” program element. The applicant stated that the program will be enhanced to include a requirement for the inspection report to be evaluated by responsible evaluation personnel who are to prepare a summary of findings and recommendations for future surveillance or repair.

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 Report AMP XI.S8.

Operating Experience. LRA Section B.2.1.38 summarizes operating experience related to the Protective Coating Monitoring and Maintenance Program. The applicant states that the program is an existing program that is used to identify degraded or deteriorated Service Level 1 coatings.

The applicant provided the following information regarding operating experience:

(1) In June 2010 an Action Request (AR) was issued to review NRC Information Notice IN 2010-12—Containment Liner Corrosion. The NRC issued this IN to inform addressees of recent issues involving corrosion of the steel reactor containment building liner. The AR response addressed all the concerns identified by the IN 2010-12. The AR concludes that: i)

Seabrook Station Containment structure is enclosed by a reinforced seismic category I concrete enclosure building which prevents exterior containment concrete from exposure to external atmosphere; ii) during construction at Seabrook Station there were three independent levels of Quality Control that provided assurance that adequate concrete placement techniques were implemented which eliminated the possibility of foreign material (organic compounds) being introduced during the concrete placement; and iii) the last IWE inspections of the containment liner performed at the Seabrook Station concluded that there were minor imperfections and discoloration in the coating film and isolated areas where the coating had been damaged, exposing the liner steel which contained only rust staining, or minor surface corrosion. In general, there was no measurable corrosion or any metal loss detected in the containment liner steel.

(2) In October 2010 an AR identified failure and degradation of Reactor Sump Liner Coating of the Unit 3 Reactor Sump Liner Plate at Turkey Point Nuclear Station. NextEra is in the process of evaluating this current AR for applicability at Seabrook.

(3) In December 1997, a Condition Report (CR) identified containment liner paint (approximately two square feet) scraped off at the scaffold storage area during the refueling outage OR05, due to poor material control practices for storing the scaffolding material. Paint in this area and other additional areas listed in the work order were repaired.

(4) In July 1998 Seabrook personnel performed a review of NRC Generic Letter GL 98-04, "Potential for Degradation of the Emergency Core Cooling System (ECCS) and the Containment Spray System (CSS) After a Loss-of-Coolant (LOCA) Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment." Seabrook Station responded to GL 98-04 via letter NYN-98125.

The staff reviewed the operating experience information in the application to determine if the applicable aging effects and industry- and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. During its review, the staff found no operating experience to indicate that the applicant’s program would be ineffective 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 application taking appropriate corrective actions. The staff confirmed that the “operating experience” program satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.38 provides the UFSAR supplement for the Protective Coating Monitoring and Maintenance Program. The staff reviewed the 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 3.5-2.

The staff also noted that the applicant committed (Commitment Nos. 46, 47, 48, and 49) to enhance the Protective Coating Monitoring and Maintenance Program prior to entering the period of extended operation. Specifically, the applicant committed to do the following:

(1) Enhance the program by designating and qualifying an inspection coordinator and an inspection results evaluator.

(2) Enhance the program to include instruments and equipment needed for inspection (i.e., flashlight, spotlights, marker pen, mirror, measuring tape, magnifier, binoculars, camera with or without wide angle lens, self sealing polyethylene sample bags).

(3) Enhance the program to include a review of the previous two monitoring reports.

(4) Enhance the program to include a requirement that the inspection report be evaluated by the responsible evaluation personnel, who is to prepare a summary of findings and recommendations for future surveillance or repair.

The staff determined 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 Protective Coating Monitoring and Maintenance Program, the staff determined 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 Nos. 46, 47, 48, and 49 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 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)(2). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides and adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.21 Metal Fatigue of Reactor Coolant Pressure Boundary Program

Summary of Technical Information in the Application. LRA Section B.2.3.1 describes the existing Metal Fatigue of Reactor Coolant Pressure Boundary Program as consistent, with enhancements, with GALL Report AMP X.M1, "Fatigue Monitoring Program." The applicant's program is a preventive measure to mitigate fatigue cracking of RCPB components by monitoring and tracking critical thermal and pressure transients for selected RCS components. This ensures the number of design transient cycles is not exceeded during the operating life and the cumulative usage factor (CUF) for these components remains less than 1.0. The applicant stated that the fatigue-sensitive components include locations such as the reactor vessel shell and lower head; reactor vessel inlet and outlet nozzles; pressurizer surge line (hot leg and pressurizer nozzles); reactor coolant piping charging system nozzle; reactor coolant piping safety injection nozzle; and RHR system Class 1 piping. The applicant also stated that the environmental effects for the fatigue-sensitive components specified in the NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," report for newer vintage Westinghouse plants have been addressed in LRA Section 4.3. Four of these components will be monitored by the applicant's program for fatigue usage, including environmental effects. These components are pressurizer surge line (hot leg and pressurizer nozzles); reactor coolant piping charging system nozzle; reactor coolant piping safety injection nozzle; and RHR system Class 1 piping, analyzed in accordance with ASME Code Section III, Subsection NB-3200.

The applicant also stated that pre-established cycle limits would identify components approaching design limits. Corrective actions for components approaching design limits include reanalysis; inspection and flaw tolerance evaluation; and repair or replace, in accordance with applicable design codes. The applicant further stated that Seabrook will enhance the Metal Fatigue of Reactor Coolant Pressure Boundary Program to include additional transients beyond those defined in the TS and the UFSAR and to use a software program to count transients to monitor cumulative usage on select components.

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 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 Report AMP X.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 Report AMP X.M1, with the exception of the "scope of program," "parameters monitored or inspected," "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.

In its review the staff noted that the scope of the applicant's program includes nuclear steam supply system (NSSS), non-NSSS components, and transients in UFSAR Section 3.9.1.1 that require tracking. LRA Section 4.3 states that the metal fatigue time-limited aging analyses (TLAAs) that are evaluated in the LRA fall into the following categories:

(a) Explicit fatigue analyses for NSSS pressure vessel and components that were prepared in accordance with ASME Code Section III, Class A or Class 1 rules, developed as part of the original design.

(b) Supplemental explicit fatigue analyses for piping and components that were prepared in accordance with ASME Code Section III rules to evaluate transients that were identified after the original design analyses were completed. Such analyses include consideration of pressurizer surge line thermal stratification and reactor vessel internal (RVI) component fatigue analyses.

(c) New fatigue analyses (also in accordance with ASME Code Section III, Class 1 rules) prepared for license renewal to evaluate the effects of the reactor water environment on the sample of high fatigue locations applicable to newer vintage Westinghouse Plants, as identified in Section 5.5 of NUREG/CR-6260, and using the methodology presented in LRA Section 4.3.4.

In addition, LRA Section 4.3.1 states that the most limiting number of transients used in these NSSS component analyses are shown in LRA Table 4.3.1-2, and are considered to be design limits. The staff confirmed that these transients are consistent with those listed in UFSAR Table 3.9(N)-1.

The staff noted that LRA Table 4.3.1-2 lists more plant design transients than those identified in TS 5.7 and TS Table 5.7-1. For example, in the TS table, normal condition transients include only plant heatup and shutdown. Upset transients include only loss of load without turbine roll, loss of all offsite power, partial loss of flow, and reactor trip from full power. Faulted transients include large steam line break, and test transients include primary and secondary side hydrostatic test and primary side leak test. It was not clear to the staff if the design CUF fatigue analyses for NSSS pressure vessels and components were based on the design transients listed in TS Table 5.7-1 or the non-TS transients that were included in LRA Table 4.3.1-2 and UFSAR Table 3.9(N)-1.

For those transients listed in LRA Table 4.3.1-2 but not in the TS, it was not clear to the staff how a transient will be accounted for, in accordance with the applicant's program during the period of extended operation. The staff noted that the "parameters monitored/inspected" program element of GALL Report AMP X.M1 states that the program monitors all plant transients that cause cyclic strains, which are significant contributors to the fatigue usage factor. By letter dated December 14, 2010, the staff issued RAI B.2.3.1-1 requesting that the applicant clarify whether the "category (a)" fatigue analysis and the "category (b)" supplemental fatigue analysis were based on transients from TS Table 5.7-1 or LRA Table 4.3.1-2 and in UFSAR Table 3.9(N)-1. The staff also asked the applicant to confirm that the plant-specific cycle-counting procedure ensures that those design transients listed in LRA Table 4.3.1-2 but not in TS 5.7 will be tracked and monitored (i.e., counted) in accordance with the Metal Fatigue of Reactor Coolant Pressure Boundary Program during the period of extended operation. In addition, the staff requested that, if these transients are not monitored during the period of extended operation, the applicant should justify with respect to the "parameters monitored/inspected" program element.

In its response dated January 13, 2011, the applicant stated that the "category (a)" fatigue analysis and the "category (b)" supplemental fatigue analysis were based on transients listed in LRA Table 4.3.1-2, and the cycle-counting procedure tracks and monitors design transients listed in this table and not those listed in TS 5.7. In response to RAI B.2.3.1-3, the applicant provided an enhanced LRA Table 4.3.1-2 detailing the current and future proposed monitoring of design transients. The additional design transients listed in the enhanced Table 4.3.1-2 are monitored by the Metal Fatigue and Reactor Coolant Pressure Boundary Program through the plant's engineering procedure for cycle-counting. The applicant further stated that the FatiguePro automated cycle-counting module will be used in companion to this procedure to count, categorize, and record the plant transients listed in the last column of enhanced LRA Table 4.3.1-2. In addition, consistent with the applicant's Commitment No. 41, normal, upset, and test condition transients defined in the TS and UFSAR will be monitored during the period of extended operation. The "initial and random steady-state fluctuations and boron concentration equalization" transients are not currently counted or proposed to be counted during the extended period because they are considered to be insignificant stress events, and their number of actual transients is not expected to approach the analyzed number of cycles. The staff finds this acceptable because the stress levels due to these transients would be below the endurance limit; therefore, it can be assumed that the number of allowed cycles is infinite. The applicant further added that emergency and faulted condition transients listed in LRA Table 4.3.1-2 are not required to be included in the fatigue evaluations and, therefore, are also not monitored by the Metal Fatigue and Reactor Coolant Pressure Boundary Program. The staff finds this acceptable. Since the faulted transients are not included in the fatigue calculations, they do not have an effect on the calculated fatigue usage and, therefore, do not require monitoring to ensure the design limit of 1.0 is not exceeded.

Based on its review, the staff finds the applicant's response to RAI B.2.3.1-1 acceptable because the applicant clarified that the fatigue analyses were based on transients listed in LRA Table 4.3.1-2 and not in TS Table 5.7-1. The applicant also enhanced LRA Table 4.3.1-2 listing all the transients that are being monitored (or will be monitored) during the period of extended operation by the Metal Fatigue and Reactor Coolant Pressure Boundary Program. Furthermore, the applicant is monitoring all cyclic-strain causing transients that are significant contributors to the fatigue usage factor and have been included in the applicant's fatigue analyses, consistent with the recommendations in the "parameters monitored/inspected" program element of GALL Report AMP X.M1. The staff's concern described in RAI B.2.3.1-1 is resolved.

In its review, the staff further noted that the scope of the applicant's program includes both NSSS and non-NSSS components as well as transients in UFSAR Section 3.9.1.1 that are required to be tracked. The applicant stated that the most limiting numbers of transients used in these NSSS component analyses are shown in LRA Table 4.3.1-2 and are considered to be design limits. However, the staff noted that the transients are termed differently in the LRA, UFSAR, and relevant documents that were reviewed during the staff's audit. For example, upset condition transients such as "inadvertent startup of an inactive loop" or "inadvertent emergency core cooling system actuation" are referred to differently in these documents. The staff also noted during its audit that the applicant's program basis document includes auxiliary transients such as "charging and letdown flow shutoff and return" or "letdown flow step decrease and return." However, these transients are not included in the list of design transients provided in LRA Table 4.3.1-2.

By letter dated December 14, 2010, the staff issued RAI B.2.3.1-2 asking the applicant to do the following:

- justify the difference of designations for the transients between LRA Table 4.3.1-2 and the CUF analyses in the applicant's program basis document
- clarify and justify how the Metal Fatigue of Reactor Coolant Pressure Boundary Program and the associated onsite procedure will be capable of tracking transient occurrences to ensure that the design limit of 1.0 is not exceeded and that any assumptions that are made in the fatigue CUF analyses remain valid, if the designations for the transients are not consistent between the LRA, the UFSAR, and other relevant documents
- clarify the significance of the auxiliary transients used in fatigue CUF analyses and explain how these transients are accounted for by the list of design transients provided in LRA Table 4.3.1-2

In its response dated January 13, 2011, the applicant acknowledged several wording differences between the transient designation listed in LRA Table 4.3.1-2 and those defined in the UFSAR Section 3.9(N).1.1 and program basis document. The applicant stated that the differences fall into the following categories:

- differences in the use of abbreviations and combining of symmetric transients such as unit loading and unloading of 5 percent of full power per minute
- addition of supplementary auxiliary transients necessary for the fatigue design basis for the chemical and volume control system (CVCS) components
- several fatigue-insignificant plant transients such as steady-state fluctuations and boron concentration equalization that are omitted from the fatigue monitoring basis document

The applicant further added that the first column of the enhanced LRA Table 4.3.1-2 lists all the transients that are included in the Fatigue Management Program and used in the fatigue analyses of the Class 1 components. The Fatigue Management Program will ensure that all fatigue-analyzed components remain within their respective design fatigue analyses results (i.e., CUF less than 1.0) by ensuring that the counted plant transients remain within the number of occurrences of each plant transient listed in the second column of enhanced LRA Table 4.3.1-2. The applicant also clarified that the six auxiliary transients listed in the enhanced Table 4.3.1-2 with footnote (6) are listed in the design specification for defining fatigue transients for CVCS components and are identified and counted in the FatiguePro software as part of the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

Based on its review, the staff finds the applicant's response to RAI B.2.3.1-2 acceptable because the applicant did the following:

- clarified the differences in the designations of the transients
- described how the Metal Fatigue of Reactor Coolant Pressure Boundary Program and Fatigue Management Program track transient occurrences
- explained the significance of the auxiliary transients used in the fatigue analyses

In addition, the applicant's program will ensure that all fatigue-analyzed components remain below the design limit of 1.0 by ensuring that the counted plant transients remain within the number of occurrences the component was analyzed for, consistent with the recommendations of GALL Report AMP X.M1. The staff's concern described in RAI B.2.3.1-2 is resolved.

In its review, the staff noted that LRA Section B.2.3.1 states that the Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors and tracks the number of transient cycles to ensure that the CUF for selected RCS components remains less than 1.0 through the period of extended operation. The applicant also stated the program ensured the environmental effect on fatigue sensitive locations are addressed. Locations with CUF approaching the design limit are reanalyzed, inspected, repaired, or replaced, as necessary, in accordance with applicable design codes. LRA Section B.2.3.1 states that pre-established action limits will permit completion of corrective actions before the design basis number of events is exceeded and before the CUF, including environmental effects, exceeds the ASME Code limit of 1.0.

However, it was not clear to the staff if the Metal Fatigue of Reactor Coolant Pressure Boundary Program will perform cycle-counting, cycle-based fatigue monitoring, or stress-based fatigue monitoring for RCPB components (including the environmentally-assisted fatigue (EAF)). Furthermore, the Metal Fatigue of Reactor Coolant Pressure Boundary Program does not provide details regarding the action limits that are set on design basis transient cycle-counting activities or on CUF monitoring activities. It also did not provide the corrective actions that will be implemented if an action limit for cycle-counting or CUF monitoring is reached. By letter dated December 14, 2010, the staff issued RAI B.2.3.1-4 asking the applicant to define and justify the "action limit or limits" that will be used by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the following:

- design basis CUF values for Class 1 components and any non-Class 1 components evaluated to Class 1 component CUF requirements
- environmentally-assisted CUF for the program's NUREG/CR-6260 equivalent or bounding locations
- Class 1 components that are within the scope of the applicant's high-energy line break (HELB) analyses for Class 1 components

In its response dated January 13, 2011, the applicant stated that the action limit for components for which CUF values are evaluated against a design limit of CUF=1.0 is 80 percent of the design or analyzed number of occurrences for any plant transient included in the fatigue analysis of any of these fatigue-analyzed components with or without EAF analysis. For any plant transient included in the fatigue analysis of the EAF-analyzed HELB components, the action limit for components, for which CUF values are evaluated against a design limit of CUF=0.1, is 80 percent of the analyzed number of occurrences. The applicant added that when any one or more of these plant transients reach a value of 80 percent or more of the design number of occurrences, a re-evaluation of each of the components analyzed for the plant transient(s) that have achieved their 80 percent limit will be performed. Also, the re-evaluation may take advantage of use of 60-year projected cycles for other transients that are included in the fatigue analysis of each of the affected components.

Based on its review, the staff finds the applicant's response to RAI B.2.3.1-4 acceptable because the action limits are set such that corrective actions can be taken prior to the cumulative fatigue usage of these components exceeding the design limit of 0.1 for HELB locations and 1.0 for all other locations, consistent with the recommendations of GALL Report AMP X.M1. The staff's concern described in RAI B.2.3.1-4 is resolved.

The staff further noted that the "corrective actions" program element in GALL X.M1 states that acceptable corrective actions include repair of the component, replacement of the component, and a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded during the period of extended operation. However, LRA Section B.2.3.1 states that corrective actions may encompass one of several activities below:

- reanalyze affected component(s) for an increase in the number of a specific transient while accounting for other component-affecting plant transients that may be projected not to achieve their analyzed levels
- perform a fracture mechanics evaluation of a postulated flaw in affected plant components, which, when coupled with an Inservice Inspection Program, will serve to demonstrate flaw tolerant behavior
- repair the affected component
- replace the affected component

By letter dated December 14, 2010, the staff issued RAI B.2.3.1-5 requesting that the applicant justify for the corrective action, to perform a fracture mechanics evaluation, which is not consistent with the recommendations of the "corrective actions" program element of GALL Report AMP X.M1.

In its response dated January 13, 2011, the applicant stated that GALL Report AMP X.M1 does not specifically address the use of a fracture mechanics evaluation to reanalyze affected components. However, the ASME B&PV Code Section XI, Appendix L, provides guidance for methods for performing fatigue assessments to determine acceptability for continued service of RCS and pressure boundary components subjected to thermal and mechanical fatigue loads. The applicant further stated that the ASME Code specified two methods for performing fatigue assessments—a fatigue usage factor evaluation and a flaw tolerance evaluation (using fracture mechanics techniques). Furthermore, these two evaluation methods are the analytical options provided in LRA Section B.2.3.1. The applicant added that the use of the flaw tolerance evaluation method would require NRC approval of fatigue crack growth curves used in the analysis.

Based on its review, the staff finds the applicant's response to RAI B.2.3.1-5 acceptable because Appendix L of the ASME Code Section XI specifies that a fatigue usage factor evaluation and a flaw tolerance evaluation using fracture mechanics techniques can be used for performing fatigue assessments, and the applicant's use of a flaw tolerance evaluation method would require NRC review and approval of the fatigue crack growth curves used in the analysis. The staff's concern described in RAI B.2.3.1-5 is resolved.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements associated with enhancements to determine if 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.2.3.1 states an enhancement to the "parameters monitored or inspected" program element. The applicant stated that its program will be enhanced to include additional transients beyond those defined in the TS and the UFSAR. The staff reviewed this enhancement and noted that the Metal Fatigue of Reactor Coolant Pressure Boundary Program does not identify these additional design transients that are monitored beyond those defined in the TS and the UFSAR. The staff also noted that the applicant's program does not provide any description or the significance of these additional transients. The applicant's program also does not identify the components that these additional transients affect, specifically those CUF TLAAs in LRA Section 4.3 that the applicant dispositioned under 10 CFR 54.21(c)(1)(iii). By letter dated December 14, 2010, the staff issued RAI B.2.3.1-3 requesting that the applicant to identify all additional design transients that are monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program, justify why these additional transients need to be monitored, and provide a discussion of the significance of these additional transients to the TLAAs identified in LRA Section 4.3. The staff also asked the applicant to clarify how these additional transients relate to TS 5.7 and the transients analyzed for in UFSAR Section 3.9. Additionally, the staff asked the applicant to clarify whether these transients were included in the new EAF analysis evaluations that were prepared for license renewal in LRA Section 4.3.4. If they were not included, the applicant must justify why these transients are significant only for those analyses in the CLB and not significant for the analyses performed for the period of extended operation.

In its response dated January 13, 2011, the applicant included an enhanced LRA Table 4.3.1-2, which provides the additional design transients that will be monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program through its plant-specific procedure for documentation of design operating transients. The applicant added that the additional transients are postulated in the design basis calculations but have not been included in the TS 5.7 and UFSAR Section 3.9. Also, the additional transients have been included in the EAF evaluations presented in LRA Section 4.3.4.

The applicant further stated that the LRA Section 4.3.1 has been revised to include the enhanced LRA Table 4.3.1-2 to identify transients that will be monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The applicant also stated that the FatiguePro automated cycle-counting module will be used as a companion to this procedure to count, categorize, and record the plant transients listed in the last column of the enhanced LRA Table 4.3.1-2. The applicant stated that the additional design transients are selected to record a comprehensive set of plant transients for the purpose of assuring that plant operation remains within the fatigue design bases of the important plant components and to provide plant operational data, should it be necessary to reanalyze plant components in the future.

The staff noted that the "parameters monitored/inspected" program element of GALL Report AMP X.M1 states that the program monitors 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.2.3.1-3 acceptable because the applicant provided the enhanced LRA Table 4.3.1-2 clarifying all the transients that are being monitored or will be monitored during the extended period by the Metal Fatigue and Reactor Coolant pressure Boundary Program. Additionally, the applicant is monitoring those additional transients that are postulated in the design basis calculations, which contribute to fatigue usage, consistent with recommendations of the "parameters monitored/inspected" program element of GALL Report AMP X.M1. Also, the applicant clarified that EAF analysis, performed to address the effects of reactor water environment on component fatigue life, consistent with the recommendations of GALL Report AMP X.M1, have included these additional transients. The staff's concern described in RAI B.2.3.1-3 is resolved.

During its review of LRA Section 4.6.2, the staff noted that the personnel airlock and equipment hatch are designed to 120 heatup and cooldown cycles. The staff also noted that the applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analyses will remain valid for the period of extended operation. The applicant's basis for this conclusion was provided in LRA Table 4.3.1-3, which shows that the 60-year projected number of heatups and cooldowns is 87 and 84, respectively. The applicant stated that the anticipated cycles for the personnel airlock and equipment hatch projected to occur during the period of extended operation is bounded by the original design of 120 heatup and cooldown cycles. The staff noted in LRA Table 4.3.1-2 the limiting design basis number of occurrences for plant heatups and cooldowns is 200 each. The staff further noted that the applicant's Fatigue Monitoring Program tracks plant transients and triggers corrective actions or re-evaluation of fatigue analyses when and if the plant approaches the design basis limit of 200 heatup or cooldown cycles but the LRA does not explain if the program will trigger corrective actions if the plant approaches 120 cycles, which is the design limit for the personnel airlock and equipment hatch.

In a conference call on November 22, 2011, the staff inquired how the applicant will track design limits related to plant startups and shutdowns as listed in LRA Section 4.6.2 related to the personnel airlock and equipment hatch . The staff noted that as previously noted in the applicant's response to RAI B.2.3.1-3 and RAI B.2.3.1-4 (Reference 3) the design limit tracked by FatiguePro is 200 plant heatups and cooldowns with an 80 percent trigger level for further evaluation. The staff noted that this action limit would exceed the design limit of 120 heatup and cooldown cycles for the personnel airlock and equipment hatch as specified in LRA Section 4.6.2.

By letter dated December 15, 2011, the applicant stated that it has revised LRA Table 4.3.1-2 previously submitted in response to RAI B.2.3.1-3 to include the specific plant startup and shutdown design limit of 120 cycles for the Personnel Airlock and Equipment Hatch. In addition, cycle counting for these specific components will initiate appropriate evaluations through the corrective action program if the 80 percent action limit is reached and that this limit will be used by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for all limits tracked in FatiguePro. The applicant stated that this action limit will provide sufficient margin and time to allow for appropriate corrective actions as defined in the Metal Fatigue of Reactor Coolant Pressure Boundary Program to be implemented prior to reaching the design limit. The staff reviewed the revised LRA Table 4.3.1-2 and confirmed that the applicant included a separate line item with a design limit of 120 cycles, which is specific only to the personnel airlock and equipment hatch analysis.

The staff noted that the applicant confirmed that there were no additional non-conservative design limits utilized in TLAA other than the plant heatups and cooldowns used in the analysis for the personnel airlock and equipment hatch.

The staff finds the applicant's supplement acceptable because (1) the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the design cycles (120 plant heatups and cooldowns) that were used in the fatigue analysis for the personnel airlock and equipment hatch will not be exceeded during the period of extended operation; (2) the program ensures sufficient time for corrective actions to be taken (i.e., reanalysis of the component, repair or replacement of the component) with an 80 percent action limit on the design cycles; and (3) the applicant confirmed that there are no other analyses that contain more limiting number of cycles that need to be incorporated into the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

Based on its review, the staff finds Enhancement 1 acceptable because the applicant will monitor these additional transients from its design basis calculations, which are not included in TS 5.7 and UFSAR Section 3.9, consistent with the "parameters monitored/inspected" program element of GALL Report AMP X.M1.

Enhancement 2. LRA Section B.2.3.1 states an enhancement to the "scope of program," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements. The applicant stated that its program will be enhanced to use a software program to count transients to monitor cumulative usage on selected components.

The "detection of aging effects" program element of GALL Report AMP X.M1 states that the AMP provides periodic update of the fatigue usage calculations. LRA Section B.2.3.1 also states that "[t]he program includes generation of a periodic fatigue monitoring report, including a listing of transient events, cycle summary event details, cumulative usage factors, a detailed fatigue analysis report, and a cycle projection report." However, the staff noted that the LRA does not provide the details regarding the software package that will be used. It is not clear to the staff if the "program" being referred to is the Metal Fatigue of Reactor Coolant Pressure Boundary Program or the software program. It is also not clear to the staff if the software package will be used for cycle-counting only or if it will also be used for cycle-based or stress-based fatigue analysis and includes periodic CUF updates.

By letter dated December 14, 2010, the staff issued RAI B.2.3.1-6 requesting that the applicant do the following:

- clarify, in detail, how the selected software package will be capable of monitoring those transients that are significant to fatigue usage such that the design limit of 1.0 is not exceeded during the period of extended operation, consistent with the recommendations in GALL Report AMP X.M1
- clarify how the software package will perform periodic CUF updates, consistent with the recommendations of the "detection of aging effects" program element of GALL Report AMP X.M1
- clarify how the software package, referenced in LRA Section B.2.3.1 and Commitment No. 42, addresses and resolves the issue associated with NRC RIS 2008-30, "Fatigue Analysis of Nuclear Power Plant Components"

In its response dated January 13, 2011, the applicant stated that the EPRI FatiguePro software is used to perform the following functions to accommodate fatigue monitoring of fatigue-critical components:

- The data acquisition system module collects plant instrument data for selected time periods.
- The automated cycle-counting module analyzes the collected plant instrument data and identifies, counts, categorizes, and records pre-defined plant transients with their pertinent engineering parameters.
- The cycle-based fatigue module calculated cumulative fatigue usage for selected plant components by applying counted plant transients to the component design stress report fatigue analysis.

The applicant also stated that the FatiguePro software would be used in conjunction with its plant-specific cycle-counting procedure to provide the technical basis and data for monitoring the number of occurrences and severity of the plant transients that define the fatigue design basis for fatigue-critical components. In addition, the data would be used to assure that the number and severity of the counted plant transients remain bounded by the component design analyses and, thereby, provide assurance that the design fatigue usage limit of 1.0 is maintained.

The applicant clarified that, as discussed above, the EPRI FatiguePro cycle-based fatigue program calculates cumulative fatigue usage for selected plant components by applying counted plant transients to the component design stress report fatigue analysis. The applicant added that the CUF computation is used as a secondary method for detecting aging effects due to fatigue; cycle-counting is the primary method for detecting aging effects.

The applicant also addressed the staff’s concern in NRC RIS 2008-30 regarding the use of simplifying assumptions when performing new ASME Code Section III NB-3200 fatigue analyses. The staff’s concern is that simplification of the six-stress tensor state to fewer stress components in the course of the fatigue analysis may lead to non-conservative fatigue usage results and should be benchmarked to six-stress tensor analyses whenever this simplification is used. The applicant clarified that the simplified method was used only in the stress-based fatigue module of the current FatiguePro software and, to resolve and address this issue, its Metal Fatigue of Reactor Coolant Pressure Boundary Program would not use the simplified FatiguePro stress-based fatigue module.

Based on its review, the staff finds the applicant’s response to RAI B.2.3.1-6 acceptable for the following reasons:

- The applicant counts, categorizes, and records the plant transients with FatiguePro in order to ensure that the design limit of 1.0 is not exceeded and the number and severity of the counted plant transients are bound by the component design analyses.
- The applicant’s Metal Fatigue of Reactor Coolant Pressure Boundary Program will periodically calculate fatigue CUF by applying counted plant transients to the component design stress report fatigue analysis, consistent with the “detection of aging effects” program element of GALL Report AMP X.M1.

- The applicant confirmed that the simplified method used only in the FatiguePro stress-based module will not be used in its Metal Fatigue of Reactor Coolant Pressure Boundary Program.

The staff's concern described in RAI B.2.3.1-6 is resolved.

The staff reviewed GALL Report AMP X.M1 and noted the following:

- The "scope of program" program element states that it includes preventive measures to mitigate fatigue cracking of metal components of the RCPB caused by anticipated cyclic strains in the material.
- The "parameters monitored/inspected" program element states the number of plant transients that cause significant fatigue usage for each critical RCPB component is to be monitored.
- The "monitoring and trending" program element states that the applicant will monitor a sample of high fatigue usage locations.
- The "acceptance criteria" program element states that it involves maintaining the fatigue usage below the design code limit.

Based on its review, the staff finds Enhancement 2 acceptable because the applicant's program, when enhanced, include preventive measures to mitigate fatigue cracking by monitoring plant transients that cause significant fatigue usage on a sample set of high fatigue usage locations and maintain usage below the design limit of 1.0 by counting transients to monitor cumulative usage on selected components with a software package, consistent with the recommendations of GALL Report AMP X.M1.

Based on its audit, and review of the applicant's responses to RAIs B.2.3.1-1 to B.2.3.1-6, the staff finds that elements one through six of the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program, with acceptable enhancements, are consistent with the corresponding program elements of GALL Report AMP X.M1 and, therefore, are acceptable.

Operating Experience. LRA Section B.2.3.1 summarizes operating experience related to the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The applicant presented several examples that demonstrate that the applicant's program can effectively manage the aging effects of fatigue damage by using industry information to identify fatigue sensitive locations and assure that the CUF meets the acceptance criterion of less than 1.0 during the period of extended operation. In 1989, the applicant responded to the NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification," by reviewing the pressurizer surge line temperature and displacement data, collected during the first operating cycle, to analyze and demonstrate the acceptability of the fatigue CUF analysis for the surge line. Also, in 1988, the applicant evaluated the possibility and effects of fluid leakage in four piping sections in the high head safety injection lines and three piping sections in charging system lines that were un-isolable from the RCS and pressurized by the charging pumps. The applicant concluded that these piping sections were not subject to stresses due to thermal stratification or temperature oscillations resulting from the mechanism described in NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems." In addition, in order to support the 60-year TLAAs associated with metal fatigue of the RCS pressure boundary, the applicant analyzed the projected CUF, incorporating environmental effects for seven locations specified in NUREG/CR-6260, and found that the CUFs for the surge line hot-leg nozzle and the charging nozzle will exceed 1.0 for 60 years of service. The staff noted that these analyses for the surge line hot-leg nozzle and the charging nozzle are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii) and will be managed by the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 if the applicant 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 corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.3.1 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 noted that it conforms to the recommended description for this type of program, as described in SRP-LR Table 4.3-2. The staff also noted that the applicant committed (Commitment Nos. 41 and 42) to enhance the Metal Fatigue of Reactor Coolant Pressure Boundary Program prior to entering the period of extended operation. Specifically, the applicant committed to the following enhancements, respectively:

- enhance the program to include additional transients beyond those defined in the TSs and the UFSAR
- enhance the program to implement a software program to count transients to monitor cumulative usage on selected components

The staff determined 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, the staff determined 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 Nos. 41 and 42 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 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 Aging Management Programs Not Consistent with or Not Addressed in the GALL Report

In LRA Appendix B, the applicant identified the following AMPs as plant-specific:

- Buried Piping and Tanks Inspection Program
- 345 kV SF_6 Program
- Boral Monitoring Program
- Nickel-Alloy Nozzles and Penetrations Program
- PWR Vessel Internals Program

For AMPs not consistent with or not addressed in the GALL Report, the staff performed a complete review to determine their adequacy to monitor or manage aging. The staff's review of these plant-specific AMPs is documented in the following sections.

3.0.3.3.1 Buried Piping and Tanks Inspection Program

Summary of Technical Information in the Application. As a result of interactions during the AMP audit conducted at the applicant's site and the applicant's review of recent significant industry operating experience, the applicant resubmitted LRA Section B.2.1.22, Buried Piping and Tanks Inspection Program, as a new plant-specific program by letter dated October 29, 2010. The applicant stated that the program will include preventive measures, including coating, cathodic protection, and backfill quality to mitigate corrosion and periodic inspections that manage the effects of aging. The applicant also stated that the program will include buried pipe, which is in direct contact with soil; underground pipe, which is located below grade within a vault that is exposed to air-indoor uncontrolled and where access is restricted; and inaccessible submerged pipe, which is located below grade within a vault that is in contact with raw water. There are no in-scope buried tanks.

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 will manage 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.2.1.22 states that the program will manage the aging effects for in-scope buried and underground piping constructed of any material, including metallic and polymeric materials. The applicant stated that the auxiliary boiler, auxiliary steam condensate, auxiliary steam heating, control building air handling, condensate, plant floor drains, diesel generator, instrument air, feedwater, fire protection and service water systems contain buried components. The applicant also stated that the auxiliary steam condensate and auxiliary steam heating systems include underground piping. The applicant further stated that the service water systems include inaccessible submerged pipe exposed to raw water.

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 structures and components 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 determined 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. However, in its

LRA, Supplement 2, dated November 15, 2010, LRA Table 3.3.2-37 was revised to include copper alloy with greater than15 percent zinc valves and bolting exposed to raw water in the submerged underground vault for service water piping. The applicant stated that the components will be managed for aging by the Buried Piping and Tanks Inspection Program. The applicant did not revise LRA Section B.2.1.22 to reflect inclusion of this material nor provide inspection frequencies.

By letter dated March 7, 2011, the staff issued RAI B.2.1.22-5 requesting that the applicant provide justification to why the program did not include copper alloy greater than 15 percent zinc and did not provide the number of planned inspections of these components.

In its response dated April 5, 2011, the applicant revised LRA Section B.2.1.22 to include copper alloy greater than 15 percent zinc components within the scope of the program and stated that two inspections will be conducted in each 10-year period starting 10 years prior to the period of extended operation.

The staff finds the applicant's response acceptable because the Buried Piping and Tanks Inspection Program scope includes all in-scope materials. Additionally, given that the copper alloy greater than 15 percent zinc components are drain valves and not a long run of pipe, two inspections in each 10-year period starting 10 years prior to the period of extended operation ensures that the applicant is conducting a sufficient number of inspections to establish a reasonable basis for the staff to conclude that the CLB function(s) of the buried in-scope components will be maintained throughout the period of extended operation. The staff's concern described in RAI B.2.1.22-5 is resolved.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1; therefore, the staff finds it acceptable.

Preventive Actions. LRA Section B.2.1.22 states that preventive actions include coatings, cathodic protection, and quality of backfill. The applicant stated that coatings were installed to industry standards on buried steel and stainless steel piping and tested during installation for holidays, faults, and missing material. The applicant also stated that backfill was controlled by plant specifications and will be evaluated during all excavations along with any evidence of damage to pipe or coatings. The applicant further stated that the cathodic protection system protects the service water, diesel generator cooling water, and instrument air piping systems as well as portions of the fire protection and control building air handling system. The applicant stated that it tests the cathodic protection system every 6 months for pipe-to-soil potentials, in accordance with National Association of Corrosion Engineers (NACE) standards.

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 the activities for prevention and mitigation programs should be described, and these actions should mitigate or prevent aging degradation.

The staff noted that the coatings and backfill quality provisions will mitigate or prevent degradation because the coatings have been installed and tested by industry standards, the backfill was controlled by plant inspections, and both will be inspected during buried pipe excavations. The staff also noted that the auxiliary boiler, auxiliary steam condensate, auxiliary steam heating, condensate, feedwater, and plant floor drains, as well as portions of the control building air handling systems, are not provided with cathodic protection. In addition, the staff noted that the LRA does not state the availability of the cathodic protection system. By letter dated December 14, 2010, the staff issued RAI B.2.1.22-1 requesting that the applicant do the following:

(a) state the availability of the cathodic protection system

(b) state the length of buried in-scope piping for systems or portions of systems not cathodically protected

(c) provide details on localized soil conditions and, if data does not exist, state what samples will be taken

(d) state the basis of the inspection population size and provide details on how plant-specific data of localized soil conditions will be used to optimize inspection locations

In its response dated January 13, 2011, the applicant stated the following:

(1) the third quarter 2010 cathodic protection availability was 98 percent and in the future, if availability drops below 90 percent or deviates from NACE criteria for greater than 90 days, those systems protected by that portion of the cathodic protection system will be considered as not having cathodic protection and will have an increased number of inspections,

(2) there is 970 feet of safety-related control building air handling, 152 feet of nonsafety-related condensate, 50 feet of nonsafety-related diesel generator, 147 feet of safety-related feedwater, and 250 feet of nonsafety-related plant floor drains buried in-scope piping without cathodic protection,

(3) localized soil condition data is not available; however, prior to buried pipe inspections, soil samples will be obtained in the area of planned direct inspections, consisting of soil resistivity, water samples, measurement of under-film liquid pH and [microbiologically-influenced corrosion] samples if applicable, and

(4) for buried in-scope steel piping systems without cathodic protection, the basis of the inspection size was multiplying the GALL Report AMP XI.M41 recommended inspection quantities for steel systems with cathodic protection by four, and if coating damage attributable to backfill material was found, a multiple of eight was used.

The staff finds the applicant's response to RAI B.2.1.22-1 items (a) and (b) acceptable. For item (a), consistent with the cathodic protection recommendations of GALL Report AMP XI.M41, the applicant will either ensure that the cathodic protection system is available greater than 90 percent of the time and not unavailable for greater than 90 days or increase its inspections quantities to that for a steel system that has no cathodic protection. For item (b), the applicant provided the length of buried in-scope piping by system for the staff to inform its evaluation of the applicant's program. The staff's concern described in RAI B.2.1.22-1 is not resolved for item (c) because the staff does not have enough information to evaluate how the applicant will evaluate soil data to determine an increase in the number of required inspections. Additionally, it is not clear to the staff that soil samples will be obtained in the vicinity of each buried in-scope steel piping system (excluding fire protection) that is not provided with cathodic protection or how often soil samples will be obtained during the period of extended operation. Additionally, the soil parameters do not appear to be sufficient to be able to determine soil corrosivity. For item (d), the staff's concern is not resolved because the basis of the program for increased quantity of inspections does not consider soil corrosivity. By letter dated March 7, 2011, the staff issued followup RAI B.2.1.22-1 (followup) requesting that the applicant state the following:

(a) what soil parameters will be used and how their aggregate impact will determine soil corrosivity

(b) whether localized soil conditions will be used to increase the number of inspection if the soil is corrosive

(c) if soil samples will be obtained in the local vicinity of all buried in-scope steel piping systems (excluding fire protection) that are not provided with cathodic protection

(d) how often soil sampling will be conducted during the period of extended operation or how it is known that localized soil conditions will not vary with time

In its response dated April 5, 2011, the applicant stated the following:

> (1) Soil sampling will include analyzing for soil resistivity, pH, redox potential, sulfides and moisture in the soil. The aggregate impact will be determined using EPRI Report 1021470, "Balance of Plant Corrosion—the Buried Pipe Reference Guide," Chapter 8, Soil Analysis, which endorses the [American Water Works Association] C105 soil corrosivity index. If the index is greater than 10, the soil is considered corrosive.
>
> (2) The number of inspections of non-cathodically protected steel pipe not containing hazardous materials will be increased from four to six, and for steel piping containing hazardous materials from five percent to 7.5 percent if the soil is determined to be corrosive. The staff noted that at the current time, the applicant does not have any non-cathodically protected in-scope buried steel pipe containing hazardous materials.
>
> (3) Soil samples will be taken at a minimum of two locations in the vicinity of in-scope non-cathodically protected steel piping to obtain representative soil conditions for each system, excluding fire protection.
>
> (4) Soil will be sampled prior to the period of extended operation to confirm that the soil conditions are not corrosive. If the initial survey shows the soil to be non-corrosive, additional soil samples will be taken every ten years thereafter during the period of extended operation to confirm the initial sample results.

The staff noted that the applicant revised LRA Section A.2.1.22, UFSAR supplement, to state that analysis for soil corrosivity is included in the program, and LRA Section B.2.1.22 to include the details as described in the April 5, 2011, response for items (a) through (d) above. The staff finds the applicant's response acceptable for the following reasons:

- The soil sample parameters and integrated effects are consistent with the standard industry practice for determining soil corrosivity.
- The increase in the number of inspections, if the soil is determined to be corrosive, is consistent with the current staff position for a system without cathodic protection.
- The number of soil samples proposed by the applicant will ensure that a representative determination of soil corrosivity can be obtained.
- The applicant will continue to confirm a non-corrosive determination by additional soil samples in the period of extended operation.

The staff's concern described in RAI B.2.1.22-1 and RAI B.2.1.22-1 (followup) are resolved.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2; therefore, the staff finds it acceptable.

Parameters Monitored or Inspected. LRA Section B.2.1.22 states that steel and stainless steel piping will be inspected for degradation of coatings. When such damage is found, the piping material will be inspected visually to detect loss of material and by surface or volumetric examination to detect cracking due to SCC in stainless steel piping or loss of wall thickness in stainless steel and steel piping. The applicant stated that polymeric materials will be inspected by manual methods for changes in material properties and visual inspection for signs of cracking, blistering, or damage. The applicant also stated that pipe-to-soil and cathodic protection current will be monitored to determine the effectiveness of the cathodic protection system. The applicant further stated that the program provides alternative means to test the integrity of buried piping systems, including the following:

- hydrostatic testing of at least 25 percent of the piping under consideration on an interval not to exceed 5 years
- internal inspection of at least 25 percent of the piping under consideration by a qualified method accepted by the staff that is capable of detecting both general and pitting corrosion at an interval not to exceed 5 years
- an annual NFPA flow test conducted on fire mains or monitoring of jockey pump operation for unexplained changes in pump activity at an interval not to exceed 1 month
- if unexplained changes occur, a flow test by the end of the next RFO

The staff reviewed the applicant's "parameters monitored or inspected" program element against the criteria in SRP-LR Section A.1.2.3.3. The SRP-LR 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) 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, surface, and volumetric inspection methods proposed by the applicant to detect loss of material and cracking where coating degradation has occurred is consistent with standard industrial practices and GALL Report AMP XI.M34, "Buried Piping and Tanks Inspection." These methods have proven to be effective in detecting loss of material or coating degradation due to the aging effects covered in the applicant's program. The staff also noted that manual inspection methods can detect changes in material properties for polymeric material. The staff further noted that, consistent with the inspection recommendations of GALL Report AMP XI.M41, the alternative means to test the integrity of the buried piping will be effective because they do one of the following:

- test the pressure-retaining capability of the piping system by an elevated pressure test which can detect current or near term leaks
- directly inspect for wall thickness degradation by volumetric means
- demonstrate that the fire protection system is capable of performing its CLB function to deliver flow

Therefore, the staff determined 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; therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.2.1.22 states that the opportunistic or directed visual inspections as described in the "parameters monitored or inspected" program element will commence 10 years prior to entering the period of extended operation and be repeated in each 10-year period of extended operation. The applicant stated that testing of the pipe-to-soil potentials and current for cathodic protection systems will be conducted annually. The applicant also stated that inspections will be performed in areas with the highest likelihood of corrosion problems.

The applicant stated that each inspection will examine a 10-ft segment of buried pipe. The number of inspections is based on the availability of cathodic protection, coating, and the adequacy of backfill materials. The number of inspections varies from one (where the cathodic protection system is installed and the backfill material is adequate) to eight (where there is no cathodic protection and the backfill material is inadequate). Additionally, the applicant has proposed to inspect 5 percent of the steel piping containing hazardous materials where the backfill is adequate and 10 percent where the backfill is not adequate and no cathodic protection is installed. As described above in the "preventive actions" program element, the number of inspections of non-cathodically protected steel pipe not containing hazardous materials will be increased from four to six and, for steel piping containing hazardous materials, from 5 to 7.5 percent if the soil is determined to be corrosive. The staff noted that, at the current time, the applicant does not have any non-cathodically protected in-scope buried steel pipe containing hazardous materials.

The staff summarized the quantity of in-scope existing buried piping inspections as shown in Table 3.0.3.3.1-1 Buried Piping Inspections, below:

Table 3.0.3.3.1-1 Buried Piping Inspections

System	Code Class or Safety Related	Contains Hazardous Materials	Material	Committed Inspections
Control Building Air Handling	Yes	No	Steel, with no cathodic protection	4/6/8[2]
Fire Protection	No	No	Steel, with no cathodic protection	4/6/8[2]
Diesel Generator	No	No	Steel, with no cathodic protection	4/6/8[2]
Plant Floor Drains (not safety related)	No	No	Steel, with no cathodic protection	4/6/8[2]
Condensate	No	No	Steel, with no cathodic protection	4/6/8[2]
Feedwater	Yes	No	Steel, with no cathodic protection	4/6/8[2]
Control Building Air Handling	Yes	No	Steel, with cathodic protection	1/NA/4[2]
Instrument Air	No	No	Steel, with cathodic protection	1/NA/4[2]

Fire Protection	No	No	Steel, with cathodic protection	1/NA/4[2]
Service Water	Yes	No	Steel, with cathodic protection	1/NA/4[2]
Condensate	No	No	Stainless Steel	1
Diesel Generator – Cooling Water[1]	Yes	Yes	Stainless Steel	1
Fire Protection	No	No	Fiberglass	1/NA/2[2]

Notes:

[1] Diesel generator cooling water piping contains glycol.

[2] The first number is the number of inspections if backfill is found to be acceptable. The second number is the number of inspections if the soil is determined to be corrosive. The third number is the number of inspections if backfill is not found to be acceptable.

The applicant stated that none of the underground piping systems contain hazardous materials, and two inspections of either the entire length of the piping or a minimum of 10 ft will be conducted. The applicant also stated that none of the inaccessible submerged piping systems contain hazardous materials, and two inspections of either the entire length of the piping or a minimum of 10 ft will be conducted. The applicant stated that the piping system is protected by a cathodic protection system and coatings are installed.

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 structure and component intended function(s). The criteria also states that parameters to be monitored or inspected should be appropriate to ensure that the structure and component 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 structure and component 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 is appropriate for detecting the aging effects covered in the program by comparing them to GALL Report AMP XI.M34, "Buried Piping and Tanks Inspection." The staff also confirmed that the use of visual inspections provides sufficient detection methods to monitor degradation of coatings and corrosion effects prior to loss of the buried steel piping intended function or failure. Additionally, the program specifies the periodicity of the inspections and location of the inspections relative to material type and risk ranking, and it ensures that inspections will be performed by excavated direct inspection of the pipe or alternative acceptable methods as described in the "parameters monitored or inspected" program element.

As discussed in the staff evaluation of the "preventive actions" program element, the staff issued RAIs B.2.1.22-1 and B.2.1.22-1 (followup) requesting that the applicant state the basis of the inspection population size and provide details on plant-specific data of localized soil conditions that will be used to optimize inspection locations. As discussed in the staff's evaluation of RAIs B.2.1.22-1 and B.2.1.22-1 (followup), above, the staff's concern described in this RAI was resolved.

In Footnote 4 of the Buried Piping Inspection Locations Table of LRA Section B.2.1.22, the applicant stated that if, during inspections of a particular material type, damage to coatings or base materials is determined to have been caused by backfill, the backfill will be considered to be "inadequate" for that material type only. The staff noted that the number of prescribed inspections increases if backfill is determined to be inadequate. In the "preventive action" program element, the applicant did not state that backfill requirements were dependent on the material type of the buried pipe. By letter dated December 14, 2010, the staff issued RAI B.2.1.22-2 requesting that the applicant justify why an inadequate backfill determination for a single material type inspection should not be applied to the other material types.

In its response dated January 13, 2011, the applicant revised Footnote 4 to state that if damage to coatings is determined to have been caused by backfill, the backfill will be considered inadequate for the purposes of the program. The staff finds the applicant's response acceptable because the applicant will use backfill quality and coatings damage inspection results to inform the number of inspections across the entire program scope. The staff's concern described in RAI B.2.1.22-2 is resolved.

The staff noted that there was insufficient information in LRA Section B.2.1.22 for the staff to evaluate the aging effects for the inaccessible steel service water submerged piping that is coated and provided with cathodic protection. By letter dated December 14, 2010, the staff issued RAI B.2.1.22-3 requesting that the applicant state how corrosion of the piping system will be detected that occurs either through permeability of the coating or coating holidays that remain undetected.

In its response dated January 13, 2011, the applicant stated that the original piping was coated with coal tar primer over which a hot, applied coal tar enamel with bonded asbestos felt or fibrous glass mat was installed. The piping was then covered with a final wrap of kraft paper/whitewash. The applicant also stated that holiday testing was conducted, and any faults were repaired. The applicant further stated that, subsequent to the original installation, pipe flanges were installed to allow for access to the interior piping. The applicant stated that the new piping was coated with a Keeler and Long 1000 Kolormastic coating system with a Tapecoat 20 primer and wrap.

The staff finds the applicant's response acceptable for the original installation because, per the NACE Resource Center glossary, coal tar epoxy creates a very water resistant film, and holiday testing is an effective method to detect holidays to allow repair of localized coating defects. The staff did not have enough information to determine that the coatings used in the modification to add flanges to the system are sufficiently waterproof. By letter dated March 7, 2011, the staff issued RAI B.2.1.22-3 (followup) requesting that the applicant provide sufficient technical data for the staff to determine that the coating is waterproof.

In its response dated April 5, 2011, the applicant stated that the Tapecoat primer and wrap is a hot applied coal tar epoxy coating system that complies with American Water Works Association C203. The applicant also stated that the Keeler and Long 1000 Kolormastic coating system is epoxy based with a dry film thickness of 5–8 mils, and two coats were applied. The applicant further stated that given that technical data from the vendor demonstrating that the Keeler and Long 1000 Kolormastic coating system is acceptable for long-term immersion is not readily available, it will conduct two inspections every 10 years by an individual qualified to inspect coatings for those portions of the piping that was coated in this manner. The applicant stated that since installation in 1995, several inspections have been conducted, and there has been no documented degradation.

The staff finds the applicant's response acceptable because the Tapecoat 20 primer and wrap is coal tar epoxy based, inspections of 10–8 mills of the Keeler and Long 1000 Kolormastic coated components is thin enough that it would readily reveal underlying corrosion, and plant-specific operating experience to date has revealed no degradation of the coating. Also, even though long-term immersion data is not readily available for the coating system, two inspections every ten years will provide adequate indication of loss of material due to corrosion. The staff's concern described in RAI B.2.1.22-3 and RAI B.2.1.22-3 (followup) are 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; therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.2.1.22 states the results of previous inspections will be evaluated (against minimum wall thickness requirements as described in the "acceptance criteria" program element) and used to assess the condition of external surfaces of other buried pipe to identify susceptible locations that warrant further inspection. The applicant also stated that pipe-to-soil potentials and currents will be monitored at least once a year and trended to identify changes in the effectiveness of the cathodic protection system. The applicant further stated that if the aging effects for the fire protection piping will be managed by monitoring for jockey pump performance, the data will be trended at least once a month.

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 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 intended function.

The staff determined the applicant's coverage of this program element to be adequate because the applicant's program will include analysis of results against minimum wall thickness criteria that will be used to identify susceptible locations that warrant further inspection. The staff also determined that trending of cathodic protection performance meets industry standard for both parameters and the frequency, and trending of jockey pump performance on a monthly basis can be effective at detecting subtle day-to-day variance in performance.

The staff confirmed that the "monitoring and trending" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.5; therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.2.1.22 states that, for coated piping, there should be no signs of coating damage and extent of coating damage will be evaluated by a qualified individual. The applicant stated the following:

- If metallic piping shows evidence of corrosion, the affected area will be evaluated against minimum wall thickness requirements.
- Cracking and blistering of polymeric piping will be evaluated under the Corrective Action Program.
- Cathodic protection pipe-to-soil potential and current will be evaluated against the criteria listed in NACE SP0169-2007.

- Backfill will be evaluated against NACE SP0169-2007, ASTM D 448-08, and whether no damage has occurred to pipe coatings.
- Flow tests results for fire main testing will be evaluated against NFPA 25.
- Unexplained jockey pump activity is evaluated under the Corrective Action Program.
- Hydrostatic test results will meet the requirement of “without leakage” contained in 49 CFR 195.302.

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 structure and component 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 structure and component 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 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 determined 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, and it relies on established design or performance-based acceptance criteria for the specific component and materials to be covered, which will be evaluated against industry standards when available. The staff also noted that qualified personnel are used to perform evaluations of coating conditions. Therefore, the staff determined 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; therefore, the staff finds it acceptable.

Operating Experience. LRA Section B.2.1.22 summarizes operating experience related to the Buried Piping and Tanks Inspection Program. The applicant stated that there are no plant-specific instances of failure of buried piping leading to loss of function of an in-scope component. The applicant also stated that it has conducted extensive visual inspections of the interior surfaces of buried service water piping and noted no staining of the cement liner; thus, it expects that there has been no penetration of the pipe wall. The applicant further stated that an opportunistic inspection of steel fire protection piping showed no degradation of the coatings. The applicant cited two instances where wrappings or coatings were damaged including buried fuel supply piping that leaked as a result of damaged wrapping where further damage was subsequently discovered and the pipe was not returned to service and another opportunistic inspection of fire protection piping that revealed that the coating was worn but the piping was not exposed.

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.

The staff noted that the applicant did not state the extent of condition review that occurred as a result of a November 2000 buried fuel supply leak that was caused by damaged wrapping. Given that portions of the buried piping systems are not cathodically protected and, thus, the only barrier to corrosion of the piping system is its coating, the staff needs to understand the extent of condition of potential coating damage in other in-scope systems. The staff also noted that, due to the extent of piping degradation, the affected portion of the in-scope buried fuel supply piping was replaced with a temporary design. The staff further noted that the applicant did not commit to replace the temporary piping prior to the period of extended operation or provide details on how the aging effects of the replacement piping will be managed. By letter dated December 14, 2011, the staff issued RAI B.2.1.22-4 requesting that the applicant state what extent of condition review beyond the inspections of the fuel oil piping system was conducted to determine the extent of coating damage in other in-scope buried piping systems. Additionally, given that the temporary piping would fulfill a license renewal function, the staff asked the applicant to describe how this piping will be age-managed during the period of extended operation.

In its response dated January 13, 2011, the applicant stated that the root cause evaluation did not result in the inspection of other buried piping as a result of this incident. The applicant also stated that the probable cause of the leak was damage to the coating, which occurred during construction. The applicant committed (Commitment No. 60) to replace the buried auxiliary boiler supply piping with a pipe-within-a-pipe design with leak detection capability prior to the period of extended operation.

The staff finds the applicant’s response acceptable because, even though the applicant did not pursue further inspections as part of the root cause analysis for the buried pipe leak, the applicant committed to conducting inspections every 10 years, starting 10 years prior to the period of extended operation through the period of extended operation. These inspections will result in a sufficient number of inspections to allow the staff to conclude that there is a reasonable basis that the in-scope buried piping will continue to meet its CLB function(s). In addition, the staff finds the applicant’s proposal to monitor the annular space in the pipe-within-a-pipe design acceptable because it is consistent with the inspection recommendations of GALL Report AMP XI.M41. The staff’s concern described in RAI B.2.1.22-4 is resolved.

Based on its review of the application, and review of the applicant’s response to RAI B.2.1.22-4, 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; therefore, the staff finds it acceptable.

<u>UFSAR Supplement</u>. LRA Section A.2.1.22 provides the UFSAR supplement for the Buried Piping and Tanks Inspection 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 Tables 3.3-2 and 3.4-2. The staff also noted that the applicant committed to do the following:

- implement the new Buried Piping and Tanks Inspection Program (Commitment No. 24)

- replace the buried auxiliary boiler supply piping with a pipe-within-a-pipe design with leak detection capability prior to the period of extended operation for managing aging of applicable components (Commitment No. 60)
- conduct soil analyses prior to entering the period of extended operation and every 10 years thereafter if the soil is determined to be non-corrosive (Commitment No. 64)

The staff determined 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 Buried Piping and Tanks Inspection Program, the staff concludes that the applicant 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).

3.0.3.3.2 345 kV SF_6 Bus Program

Summary of Technical Information in the Application. LRA Section B.2.2.1 describes the new 345 kV SF_6 Bus Program as a plant-specific program. The applicant states that this program will manage the following aging effects on the 345 kV SF_6 Bus:

- loss of pressure boundary due to elastomer degradation
- loss of material due to pitting, crevice, and galvanic corrosion
- loss of function due to unacceptable air, moisture, or sulfur dioxide (SO_2) levels

Sulfur hexafluoride (SF_6) is an inert gas used to insulate the bus conductor. The program will inspect for corrosion on the exterior of the bus duct housing, test for leaks at elastomers, and periodically test SF_6 gas samples to determine air, moisture, and SO_2 levels. The presence of air or moisture may lead to the loss of intended function. SO_2 levels are an indication of partial discharge internal to the bus ducts.

Staff Evaluation. The staff reviewed the program elements one through six of the applicant's program against the acceptance criteria for the corresponding elements as stated in SRP-LP Section A.1.2.2. 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 the 345 kV SF_6 Bus Program is credited for maintaining the pressure boundary formed by the exterior metal housing and elastomers. The program also monitors critical SF_6 parameters such as air, moisture, and SO_2 levels. The SF_6 Bus Program will routinely monitor the integrity of the elastomers by performing leak tests.

The 345 kV SF_6 Bus AMP in-scope bus segments are those bus segments included in the recovery path for an SBO event. Two possible recovery paths are identified as follows:

- The first path includes the SF_6 bus from 345 kV Power Circuit Breakers 11 and 163 to the generator step-up transformer and to the unit auxiliary transformers via the isolated phase bus.

- The second path includes the SF_6 bus from 345 kV Power Circuit Breakers 52 and 695 to the reserve auxiliary transformers.

The staff reviewed the applicant's "scope of program" program element against the criteria in SRP-LR Section A.1.2.3.1, which states that the scope of program should include the specific structures and components of which the program manages the aging.

The specific commodity groups for which the program manages aging effects are identified as the two paths above, 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; therefore, the staff finds it acceptable.

Preventive Actions. LRA Section B.2.2.1 states that actions of the 345 kV SF_6 Bus Program is to perform tests and inspections. The applicant stated that tests and inspections shall be performed prior to entering the period of extended of operation and at least once every 6 months thereafter. No preventive actions are taken as part of this program to prevent or mitigate aging degradation.

The "preventive actions" program element criterion in SRP-LR Section A.1.2.3.2 is that Condition Monitoring Programs do not rely on preventive actions; thus, preventive actions need not be provided. The staff determined that the preventive actions program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2. The staff finds it acceptable because this is a Condition Monitoring Program, and there is no need for preventive actions. The staff finds this program element acceptable.

The staff confirms that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2; therefore, the staff finds it acceptable.

Parameters Monitored or Inspected. LRA Section B.2.2.1 states that the 345 kV SF_6 Bus Program performs tests and inspections to maintain the critical parameters of the SF_6 bus system prior to entering the period of extended of operation and at least once every 6 months thereafter. Critical parameters of the SF_6 bus system are mechanical integrity of the system to maintain a pressure boundary and maintenance of acceptable air, moisture, and SO_2 levels. The applicant stated that the program includes pressure monitoring of the SF_6 gas to insure that adequate insulating properties are maintained. The applicant also stated that the program performs periodic tests on samples of the SF_6 gas to determine air, moisture, and SO_2 levels as well as inspections for loss of materials on the exterior surfaces of the duct.

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 the parameters to be monitored or inspected should be identified and linked to the degradation of the particular structure and component intended function(s). Additionally, for a Condition Monitoring Program, the parameters monitored or inspected should detect the presence and extent of aging effects.

The parameters monitored or inspected will provide evidence of degradation of the insulating properties of the SF_6 gas via sample testing. Also, the pressure monitoring of the SF_6 gas and detection of loss of materials on the SF_6 bus duct system will help to maintain its pressure boundary and 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 of the SRP-LR; therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.2.2.1 states that the 345 kV SF_6 Bus Program tests samples of the SF_6 gas to determine if the insulating properties are adequate. These tests are focused on air, moisture, and SO_2 levels. The SO_2 measurements provide an indication of arcing internal to the bus. The gas is sampled, and its properties are tested prior to entering the period of extended operation and at least once every 6 months thereafter.

The applicant stated that the program maintains the pressure boundary by monitoring the pressure of SF_6 gas and inspecting for leaks. The system SF_6 bus will be inspected for leaks prior to entering the period of extended operation and at least once every 6 months thereafter.

The applicant also stated that the program performs visual inspections on the exterior surfaces of the duct prior to entering the period of extended operation and at least once every 6 months thereafter.

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 structures and components 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., testing samples of SF_6 gas, visual inspection for surface of duct), frequency, and timing of inspection to ensure timely detection of aging effects.

Testing samples of SF_6 gas for insulating properties and visual inspection of the bus duct are an acceptable method to detect a degradation of SF_6 bus systems. The staff also determined that periodic tests on samples and visual inspection every 6 months are adequate to detect the degradation of insulating properties.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4; therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.2.2.1 states that the 345 kV SF_6 Bus Program includes trending actions of the SF_6 properties. The applicant stated that trending provides additional data, which can be analyzed to determine the rate of change in the measured parameters against the acceptance criteria. The applicant further stated that analysis of the collected data against the acceptance criteria and inspection may result in corrective actions.

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 affect 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 staff determined that once every 6 months testing and visual inspection for monitoring and trending and activities is acceptable since testing and inspection provide a prediction regarding the rate of degradation in order to confirm that timing of the next scheduled inspection and testing will occur before a loss of the structure and component intended function.

The staff confirmed that the “monitoring and trending” program element satisfies the criterion defined in the SRP-LR Section A.1.2.3.5; therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.2.2.1 states that the 345 kV SF_6 Bus Program performs leak tests, tests the quality of SF_6 gas, and inspects for loss of material. The applicant described the following criteria as acceptance criteria:

> The Seabrook program maintains the pressure boundary by inspecting for leaks and monitoring SF_6 gas pressure. The minimum acceptable pressure value is sufficient to provide adequate insulation between the conductor and the exterior housing. The SO_2 measurements of the SF_6 gas provide an indication of partial discharge occurring internal to the bus. Any indication of the presence of SO_2 will be evaluated by engineering staff. The evaluation will provide corrective action required.
>
> A dew point check is used to determine the moisture content of the SF_6 gas. The maximum allowable dew point measurement is below the dew point value that would lead to break-down of the insulation.
>
> Purity check is used to determine the air content of the SF_6 gas. The maximum allowable air content is below the value that would lead to breakdown of the insulation.
>
> Visual inspection on the exterior surfaces of the duct will detect the presence of pitting, crevice, and galvanic corrosion. Engineering evaluations will be performed if corrosion is found on the duct. The evaluation will determine the ability of the remaining wall thickness to maintain the required pressure boundary.

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 their bases should be described. The acceptance criteria, against which the need for corrective actions will be evaluated, should ensure that the structure and component intended function(s) are maintained under all CLB design conditions during the period of extended operation.

The acceptance criteria for the tests and inspection provide assurance that the SF_6 gas maintains its intended function as the bus insulation under CLB design conditions.

The staff determined that the “acceptance criteria” program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6; therefore, the staff finds it acceptable.

Operating Experience. LRA Section B.2.2.1 summarizes operating experiences related to the 345 kV SF_6 Bus Program. The applicant stated that Seabrook routinely performs monitoring and test activities for various parameters of the SF_6 bus. The inspections and tests are performed as part of maintenance activities. Results that are not acceptable are documented in the Corrective Action Program.

The applicant stated that the program relied on a review of the Corrective Action Program database to provide the basis of this review. The applicant also stated that its review of the recent operating experience for the SF_6 leak inspections at Seabrook increased the reliability of the SF_6 switchyard. Also, in 2008, the applicant experienced an increase in the level of SO_2 in a sample of the SF_6 gas. An engineering evaluation attributed the increase to thermal cycling or partial discharge, which occurs with normal switch operation. The SF_6 gas was filtered. This operating experience demonstrates the ability of Seabrook to routinely detect and analyze anomalies prior to loss of intended function. Plant-specific and industry operating experiences will be evaluated in the development and implementation of this program. As additional operating experience is obtained, the applicant will incorporate lessons learned into the program.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which states that operating experience with existing programs 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 structure and component 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 audit and review of the application, the staff finds that operating experience related to the applicant's program demonstrates that the program can adequately manage the detrimental effects of aging on SSCs within the scope of the program and implementation of the program has resulted in the applicant taking corrective actions. The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.2.1 provides the UFSAR supplement for the 345 kV SF_6 Bus Program. The staff reviewed the UFSAR supplement description of the program and noted that it conforms to the recommendation for this type of program, as described in SRP-LR Section 3.6.3.4 and Table 3.6-2.

The staff also noted that the applicant committed (Commitment No. 40) to implement the 345 kV SF_6 Bus Program prior to entering the period of extended operation for managing aging of applicable components.

The staff determined 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 345 kV SF_6 Bus Program, the staff concludes that the applicant 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 Boral Monitoring Program

Summary of Technical Information in the Application. LRA Section B.2.2.2 describes the existing Boral Monitoring Program as plant-specific. The applicant stated that the program manages the aging effects of reduction of neutron absorbing capacity due to Boral degradation. It also manages changes in the dimensions and loss of material due to general corrosion of Boral neutron absorbing material in the spent fuel pool racks by relying on representative coupon samples mounted in a coupon "train" located in the spent fuel pool to monitor performance of the absorber material without disrupting the integrity of the storage system. The applicant further stated that the program assures the Boral neutron absorbers in the spent fuel racks maintain the validity of the criticality analysis in support of the rack design.

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 applicant's spent fuel pool is divided into two regions. The applicant further stated that region one has six racks with Boral as the neutron absorber that allow space for 576 fuel assemblies. The applicant further stated that region two contains Boraflex as the neutron absorber and is not credited in the criticality analysis; therefore, region two is not within the scope of license renewal. The applicant also stated that the scope of the program is the management of the reduction of neutron-absorbing capacity of the Boral sheets in region one. The applicant stated that this is accomplished by monitoring neutron-absorbing capacity, inspecting for changes in dimensions and inspecting for loss of material due to general corrosion caused by the effects of the spent fuel pool environment on representative Boral coupons.

The staff reviewed the applicant's "scope of 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 structures and components of which the program manages the aging, and it finds that the applicant adequately described the structures and components to be managed.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1; therefore, the staff finds it acceptable.

Preventive Actions. LRA Section B.2.2.2 states that the applicant's Boral Monitoring Program is a Condition Monitoring and Inspection Program; therefore, there are no preventive actions required.

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; thus, this information need not be provided.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2; therefore, the staff finds it acceptable.

Parameters Monitored or Inspected. LRA Section B.2.2.2 states that the applicant uses standard Boral coupons of the same design as, and traceable to, the specific Boral heat lot material used in the fabrication of the spent fuel racks. The applicant stated that the standard coupons are placed in the spent fuel pool for monitoring of the aging effects and control coupons were supplied, in addition to standard coupons, to benchmark coupon initial conditions, to monitor possible pool conditions, and to demonstrate comparisons between different examination techniques and service contractors. The applicant further stated that the program monitors changes in the physical properties of the Boral coupons such as blistering, pitting, cracks, corrosion and spalling, loss of material, and other damage or condition. The applicant also stated that the physical dimensional requirements of the coupons are also monitored, and two or more Boral coupons are selected each RFO for examination by an outside contractor where neutron attenuation, neutron radiography examination, and other nondestructive examinations are performed.

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 SRP-LR also states that, for a Performance Monitoring Program, a link should be established between the degradation of the particular structure or component intended function(s) and the parameter(s) being monitored.

After reviewing the "parameters monitored or inspected" program element, the staff determined that the applicant adequately addressed the criterion defined in SRP-LR Section A.1.2.3.3. Inspection of the Boral coupons, which are indicative of the Boral in the spent fuel pool, is an acceptable means to monitor for the aging effects of loss of material and reduction of neutron absorber capacity. Furthermore, monitoring the physical condition of the neutron-absorbing material, such as geometric changes in the material (formation of blisters, pits and bulges), and decreased boron areal density makes this element of the program consistent with LR-ISG-2009-01, "Aging Management of Spent Fuel Pool Neutron-Absorbing Materials other than Boraflex."

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3; therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.2.2.2 states the Boral Monitoring Program monitors coupon samples located in the spent fuel pool to determine the condition of the neutron absorber material without disrupting the integrity of the spent fuel storage system. The applicant stated that the program measures certain physical and chemical properties of these sample coupons each RFO. The applicant further stated that the program maintains the coupon train within the spent fuel pool positioned such that the coupons experience the same conditions as the Boral panels built into the actual fuel racks. The applicant further stated that the coupons are mounted in stainless steel jackets and stainless steel coupon train mimicking the construction of the fuel racks designed to recreate the spent fuel pool environment for known effects and potential effects that may be unknown at this time

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 loss of the structure and component intended function(s). The parameters to be monitored or inspected should be appropriate to ensure that the structure and component 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 and one-time inspections to ensure timely detection of aging effects. Additionally the program should provide information that links the parameters to be monitored or inspected to the aging effects being managed.

After reviewing the "detection of aging effects" program element, the staff determined that the applicant adequately addressed the criterion defined in SRP-LR Section A.1.2.3.4 because the Boral Monitoring Program is set up to facilitate early detection of aging effects in the Boral sheets in the spent fuel pool via detection of aging effects in the Boral coupons. The Boral Monitoring Program tests selected coupons every RFO, exposes the coupons to a similar environment to that of the actual Boral in the spent fuel pool, and maximizes the amount of exposure the coupon trains receive while in the spent fuel pool.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4; therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.2.2.2 states that the neutron attenuation tests are trended to ensure that degradation does not challenge the assumptions within the spent fuel pool criticality analysis of record. The applicant stated that observable loss in neutron attenuation ability, if any, is projected to determine when neutron attenuation may fall below acceptance criteria. Additionally, the applicant stated that, along with size and weight measurements to determine the extent of shrinkage or loss of material, blister shape and size are recorded and trended to determine whether new blisters are forming, the rate of growth of existing blisters, and the rate of increase in blister thickness.

The staff reviewed the applicant's "monitoring and trending program" 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 or industry-wide operating experience or both may be considered in evaluating the appropriateness of the technique and frequency.

After reviewing the "monitoring and trending" program element, the staff determined that the applicant adequately addressed the criterion defined in SRP-LR Section A.1.2.3.5 because the applicant's Boral Monitoring Program includes trending of the degradation of the boral coupons as well as the physical characteristics of the coupons, which is congruent with the recommendations, as described in SRP-LR Section A.1.2.3.5.

The staff confirmed that the "monitoring and trending" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.5; therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.2.2.2 states that the purpose of the applicant's Boral Monitoring Program is to ensure that degradation does not challenge the design bases and assumptions within the spent fuel pool criticality analysis of record. The applicant further stated that the design of the region one spent fuel racks containing Boral as a neutron absorbing material assures a K_{eff} less than 0.95 (5 percent subcriticality margin). The applicant stated that the acceptance criteria for the following properties are applied to each exposed standard Boral coupon inspected.

The applicant stated that failure to meet acceptance criteria is addressed by the following engineering evaluation:

a. Voided Blister Displacement—the total blister void volume for all blisters present on both sides of a coupon will be less than a 45 mil uniform void over the area of the coupon. The rate of change in blister displacement provides indication of availability of sufficient margin to avoid exceeding the 45 mil uniform void prior to the next Boral coupon examination.

b. Boron Carbide Loss—B^{10} areal density measured by thermal neutron attenuation will be greater than 0.02 gm/cm^2 [grams per square centimeter] as specified within the criticality analysis and material specification. The rate of change in boron carbide loss provides indication of availability of sufficient margin to maintain the 0.02 gm/cm^2 B^{10} areal density beyond the next Boral coupon examination.

c. Boron Carbide Redistribution—Boron carbide distribution will be uniform as observed by thermal neutron radiography. Thinned or depleted areas will satisfy the criterion for boron carbide loss discussed above.

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 structure and component 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.

After reviewing the "acceptance criteria" program element, the staff determined that the applicant adequately addressed the criterion defined in SRP-LR Section A.1.2.3.6 because the acceptance criterion listed in the applicant's Boral Monitoring Program are congruent with the recommendations of SRP-LR A.1.2.3.6. These acceptance criterion will ensure that the structure and component intended function(s) are maintained under all CLB design conditions 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; therefore, the staff finds it acceptable.

<u>Operating Experience</u>. LRA Section B.2.2.2 summarizes operating experience related to the Boral Monitoring Program. The applicant stated that the Boral Monitoring Program is an existing AMP proposed for the period of extended operation.

The applicant stated that the operating experience included the following:

(1) During planned work involving an inspection of the Spent Fuel Pool Boral coupon tree in 2003, an unexpected blistering of the Boral material was identified when one of the Boral coupons was examined.

  a. The condition report evaluation concluded that the effect on the current Spent Fuel Pool criticality analysis was insignificant and the current blistered condition was acceptable as is. The evaluation stated that the degree of Boral blistering was expected to increase with repeated exposure to gamma energies present during offload; as such, a Boral monitoring program was established to evaluate future changes in the Boral material. Since the Boral monitoring program would not gather any additional data on the blistering events until after the next core offload, a water reduction in the flux trap equal to 90 mils was analyzed and applied to the revised criticality analyses to formally accommodate any increased blistering at offload.

  b. The revised type determination curves are conservative to the existing curves at all points, and were implemented prior to core offload. The type determination curves with the 90 mil allowance were included to accommodate any future blistering. This allowance is used as an acceptance criterion for the Boral monitoring program. Other acceptance criteria will include the $Boron^{10}$ areal density.

(2) As of January 2003, a Boral Monitoring Program had not yet been formally established following implementation of the engineering change to incorporate Boral instead of Boraflex in the second set of fuel racks. Although no commitment had been made to implement such a program,

Seabrook Station opted to establish a Boral coupon monitoring program as a good practice.

(3) During the Cycle 10 monitoring program (Spring of 2005), aluminum cladding oxidation and spalling was observed on Boral coupons. Photos of these coupons taken in the previous monitoring cycle were reviewed and showed oxidation but no evidence of spalling. The progression and effect of this oxidation and spalling was evaluated and predicted to remain within the program acceptance criteria through the next coupon examination in Cycle 11, when the material would be re-evaluated.

The Boral oxidation and spalling condition was described and posted with [Institute of Nuclear Plant Operation] INPO as operating experience on August 26, 2005.

The Cycle 11 examinations (Fall of 2006) indicated continued aluminum cladding oxidation on most coupons. The potential degradation of neutron absorbing capacity due to continued, and eventually through-wall, oxidation and spalling was evaluated by observing previously dissected blisters on special coupon A131. Blisters on this coupon had been intentionally dissected to investigate the effect on the Boral should a blistered area break through. By dissecting the blisters, the cermet [ceramic-metallic] compound was now exposed directly to the Spent Fuel Pool water. The altered coupon A131 with dissected blisters had been exposed to the Spent Fuel Pool conditions for approximately 3 years, and was then indicating measurable change in B^{10} areal density in the bare cermet.

The results of the Cycle 11 examinations indicated continued aluminum cladding oxidation. The Boral coupons did, however, remain well within the areal density specification. The change in B^{10} areal density was just above the lower limit of detection by visual examination. The corrosion process appeared to be proceeding very slowly.

The potential for measurable B^{10} loss in the unaltered coupons was reasonably expected within the next few cycles. Therefore long term B^{10} areal density monitoring, via neutron attenuation, was also implemented to ensure conformance to Boral specifications.

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 structure and component intended function(s) will be maintained during the period of extended operation.

The staff reviewed neutron radiography examination data as well as the applicant's technique for determining areal density of the Boral coupons. This technique involves performing visual examinations of the radiographical images of coupons. During its review, the staff identified 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. The staff determined the need for additional clarification, which resulted in the issuance of an RAI.

In LRA Section B.2.2.2 the applicant stated that Boral coupons are selected each RFO for examination by an outside contractor. By letter dated December 14, 2010, the staff issued RAI B.2.2.2-1 requesting additional information on how the coupons were handled by the applicant and the contractor to ensure the condition of the coupons were representative of the coupons upon exiting the pool and not due to the handling and transportation of the coupons to the testing facility.

In its response dated January 13, 2011, the applicant provided excerpts from both the contractor procedure and its own program documents detailing the controls put in place to ensure consistent and effective handling and testing of the Boral coupons. The applicant further provided details on the different tests done on the coupons once they arrive at the contractor facility. Based on its review, the staff finds the applicant's response to RAI B.2.2.2 acceptable because the applicant demonstrated the appropriate level of care to ensure that the coupons analyzed are the most representative of the Boral in the spent fuel pool.

Based on its review of the application, and review of the applicant's responses to RAI B.2.2.2, 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; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.2.2 provides the UFSAR supplement for the Boral Monitoring 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 LR-ISG-2009-01.

The staff determined 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 Boral Monitoring Program, the staff concludes that the applicant 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 Nickel-Alloy Nozzles and Penetrations Program

Summary of Technical Information in the Application. LRA Section B.2.2.3 describes the existing Nickel-Alloy Nozzles and Penetrations Program as plant-specific. The applicant stated that the Nickel-Alloy Nozzles and Penetrations Program manages the aging effect of cracking due to PWSCC of nickel-based alloy pressure boundary and structural components exposed to reactor coolant.

Staff Evaluation. The staff reviewed program elements one through six and ten 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.

GALL Report Table 3.1-1, IDs 31 and 34,and their subordinate items, are unique in the GALL Report in that they do not recommend that aging be managed through the use of an AMP contained in the GALL Report. Rather, they recommend specific aging management activities. For nickel-alloy materials addressed by these AMR items, the recommended aging management activities consist of the following:

- use of Inservice Inspection (IWB, IWC, and IWD) AMP
- use of Water Chemistry AMP
- compliance with all NRC Orders
- commitment to implement applicable bulletins and generic letters
- commitment to implement staff accepted industry guidelines

The approach taken by the GALL Report for these AMR items permits license renewal applicants to demonstrate consistency with the GALL Report by citing these aging management activities in their LRA AMR items. Alternatively, as has been done in this case, consistency with the GALL Report may be demonstrated for these items by developing an AMP and citing it for each applicable AMR item, which is consistent with SRP-LR Section A.1.2.3 and which addresses all of the recommended aging management activities listed above. The staff's review of this AMP is, therefore, designed to verify consistency with SRP-LR Section A.1.2.3 and to ensure that the aging management activities listed for nickel-alloy components included in GALL Report Table 3.1-1, IDs 31 and 34, are addressed by the AMP.

Scope of the Program. LRA Section B.2.2.3 states that the Nickel-Alloy Nozzles and Penetrations Program is an existing program that manages the effects of aging of nickel-alloy components including alloy 82/182 weld metal in accordance with industry guidance documents, ASME B&PV Code, Code Case N-722, and 10 CFR 50.55a. The scope of the program element contains a specific list of components, which are included within the scope as well as a general specification of components, which are excluded. This section also states that the AMP complies with applicable NRC Orders and implements applicable NRC bulletins, generic letters, and staff-accepted industry guidelines.

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 structures and components for which the program manages aging.

Based on the list provided, which addresses materials and components included within the scope of 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; therefore, the staff finds it acceptable.

Preventive Actions. LRA Section B.2.2.3 states that the Water Chemistry Program AMP is used to prevent and mitigate PWSCC. Additionally, this section of the LRA states that several other preventive and mitigative techniques are available for use. These techniques include mechanical stress improvement, induction heat stress improvement, weld overlay, mechanical nozzle seal assembly, zinc injection, abrasive water jet, nickel plating, or replacement with Alloy 690/52/152 components.

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 activities for prevention and mitigation programs should be described.

Based on the description of the available mitigative techniques, the staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2; therefore, the staff finds it acceptable.

Parameters Monitored or Inspected. LRA Section B.2.2.3 states that the program monitors cracking due to PWSCC of Alloy 600/82/182 materials exposed to reactor coolant. This LRA section also states that the program performs condition monitoring examinations of the lower reactor vessel head surface and each bottom-mounted instrumentation tube penetration. This LRA section additionally states that these examinations monitor for through-wall cracks that may exist in the nozzles or their associated partial penetration J-groove welds. This LRA section further states that, for other in-scope pressure boundary components, the program monitors for evidence of reactor coolant leakage which may manifest itself in the form of boric acid residues or corrosion products. This LRA section finally states that the core support pads and lugs and clevis inserts are VT-3 inspected once per interval for evidence of 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 structure and component intended function(s). Additionally, for a condition Monitoring Program, the parameters monitored or inspected should detect the presence and extent of aging effects.

The staff finds that, for the components under consideration, cracking is the degradation mechanism, which will affect their intended function and that the exams included in the program will be capable of directly detecting cracks or will be capable of detecting secondary evidence of cracks (e.g., boric acid). Based on this finding, the staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3; therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.2.2.3 states that visual, surface, and volumetric exams are used to detect cracking due to SCC in Alloy 600/82/182 components. In this element, the applicant also states that SSCs will be inspected in accordance with the ASME Code, Section XI, Subsections IWB, IWC, and IWD Program.

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 structure and component intended function(s). The criteria also states that parameters to be monitored or inspected should be appropriate to ensure that the structure and component 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 structure and component 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.

In its review, the staff determined that cracking is an appropriate parameter to monitor to ensure the maintenance of intended function of the components under consideration. The staff also determined that a combination of visual, surface, and volumetric test methods were capable of detecting cracking or secondary evidence of cracking, e.g., boric acid, prior to loss of intended function. The staff additionally determined that this AMP refers to the *Code of Federal Regulations*, the ASME Code, and various code cases and that the specifications (how, where, when) for these inspections are contained in these documents. The staff finally determined that there is no industry- or plant-specific operating experience, which necessitates deviating from the inspections proposed in this program element.

Based on the above evaluation, the staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4; therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.2.2.3 states that the program incorporates the inspection schedules and frequencies for the nickel-alloy components in accordance with the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and, where applicable, ASME Code Case N-722, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(E). This section also provides a list of inspections to be conducted including the frequency of those inspections.

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 or industry-wide operating experience or both 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.

In this review, the staff determined that this program element adequately describes the monitoring and trending that is proposed. The staff also determined that the governing documents for the inspections to be monitored and trended provide sufficient guidance concerning inspection frequency and the modification of that frequency based on past inspections, or other plant-specific or industry operating experience, to provide timely corrective action or mitigation or additional inspections prior to loss of intended function. The staff further determined that the program element and the governing documents provided sufficient guidance to allow collected data to be compared to applicable acceptance standards.

Based on the above evaluation, the staff confirmed that the "monitoring and trending" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.5; therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.2.2.3 states that acceptance criteria for this program are contained in governing documents, e.g., ASME Code and Code Cases.

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 to include ensuring that the structure and component 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 structure and component 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.

In its review, the staff determined that the acceptance criteria for these inspections are clearly defined in the program element or in the governing documents. The staff also has no reason to believe that these values, many of which carry the force of regulation, would not allow for the intended function of the components under consideration to be maintained during the period of extended operation under all CLB design loads.

Based on the above review, the staff confirmed that the “acceptance criteria” program element satisfies the criterion defined in SRP-LR Section A.1.2.3.6; therefore, the staff finds it acceptable.

Operating Experience. LRA Section B.2.2.3 summarizes operating experience related to the Nickel-Alloy Nozzles and Penetrations Program. In this program element, the applicant provided results from six different inspections and, when necessary, the corrective actions that were taken as a result of these inspections. The inspections described included hot leg nozzles, lower head penetrations, pressurizer butt welds, steam generator bowl drain connections, pressurizer nozzles, and reactor vessel nozzle butt welds. During these inspections, one axial flaw was discovered in 82/182 weld material in the reactor vessel Loop “D” hot leg nozzle. This flaw was mitigated via the mechanical stress improvement process. Additionally, six pressurizer nozzles were preemptively mitigated via the installation of Alloy 52M full structural weld overlays.

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.

In this review, the staff found that the applicant was conducting the inspections in accordance with the regulation, the ASME Code, and this AMP. The staff also found that the applicant was correctly responding to the findings of the inspections. Based on the preemptive mitigation conducted by the applicant, the staff concluded that the applicant was appropriately addressing the issue of PWSCC.

Based on this review, the staff finds that operating experience related to the applicant’s program demonstrated 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; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.2.3 provides the UFSAR supplement for the Nickel-Alloy Nozzles and Penetrations Program.

The staff reviewed this UFSAR supplement description of the program and noted that it provides an adequate description of the program. However, the staff also noted that the applicable bulletins, generic letters, and staff-accepted industry guidelines are not included in the UFSAR description of the program or commitments.

By letter dated December 14, 2010, the staff issued RAI B.2.2.3-1 requesting that the applicant provide justification to why the applicable bulletins, generic letters, and staff-accepted industry guidelines are not necessary in the UFSAR supplement or commitment.

In its response dated January 13, 2011, the applicant provided a commitment to implement applicable bulletins, generic letters, and staff-accepted industry guidelines.

The staff finds this response acceptable because the applicant committed to the implementation of applicable bulletins, generic letters, and staff-accepted industry guidelines, and is consistent with GALL Report Table 3.1-1, IDs 31 and 34, and their subordinate items. The staff's concern described in RAI B.2.2.3-1 is resolved.

The staff determined that the information in the UFSAR supplement, as amended by the commitment provided, is an adequate summary description of the program, as required by 10 CFR 54.21(d) and is, therefore, acceptable.

Conclusion. On the basis of its technical review of the applicant's Nickel-Alloy Nozzles and Penetrations Program, the staff concludes that the applicant demonstrated that, through the use of this AMP, the effects of aging of nickel alloys may be adequately managed so that the intended function(s) of the components under consideration 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 Pressurized-Water Reactor Vessel Internals Program

Summary of Technical Information in the Application. LRA Section B.2.1.7 describes the PWR Vessel Internals Program as plant-specific. The applicant stated that the PWR Vessel Internals Program is a new program which manages the aging effect of cracking due to irradiation-assisted stress corrosion cracking (IASCC), PWSCC, intergranular stress corrosion cracking (IGSCC), reduction in fracture toughness due to radiation and thermal embrittlement, void swelling, and loss of preload in RVI components.

Staff Evaluation. The staff reviewed program elements one through six and ten 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.2.1.7 states that the PWR Vessel Internals Program is a new program that manages the effects of aging of bolted and non-bolted RVI components in the upper and lower internals assemblies. The scope of the program element contains a specific list of components, which are not included within the scope. This section also states that the AMP will follow the NRC-approved inspection and evaluation guidelines with primary inspections on components that are highly susceptible to at least one of the aging mechanisms and have a relatively high consequence of failure. When primary inspections detect significant aging, the program requires inspection expansion to include additional highly and moderately susceptible components that have moderate consequence of failure. Some susceptible components are already covered by existing AMPs that are capable of managing the effects of aging and are specifically not included. No additional measures are appropriate for other components because they would have little consequence if they did happen to fail. This categorization of components does not supersede the ASME Code Section XI ISI requirements.

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 structures and components for which the program manages aging.

Based on the applicant's commitment to follow the NRC-approved inspection and evaluation guidelines, which addresses materials and components included within the scope of 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; therefore, the staff finds it acceptable.

Preventive Actions. LRA Section B.2.1.7 states that the PWR Vessel Internals Program is a Condition Monitoring Program to perform inspections, and it does not include preventive actions. The Water Chemistry Program, LRA Section B.2.1.2, is used to prevent and mitigate cracking by controlling the concentrations of detrimental contaminants below the levels that are known to cause degradation. The Water Chemistry Program includes the specifications for chemical species, test frequency for sampling and analysis, as well as corrective actions to maintain control of the water chemistry within the vessel.

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 activities for prevention and mitigation programs should be described.

Based on the description of the existing AMP in LRA Section B.2.1.2, the staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2; therefore, the staff finds it acceptable.

Parameters Monitored or Inspected. LRA Section B.2.1.7 states that the program monitors the extent of aging degradation of the reactor internals with one-time, periodic, and conditional inspections (visual, surface, or volumetric examinations and physical measurements), and other aging management methodologies, as needed, in accordance with the NRC-approved inspection and evaluation guidelines and the ASME Code Section XI ISI Program.

Where visual inspections are required, the applicant stated that VT-3 visual techniques are credited for the inspections. The applicant also states that the program performs either VT-1 or enhanced VT-1 (EVT-1) visual inspections when surface discontinuities and imperfections on the surface must be detected while subsurface discontinuities and imperfections will be detected with volumetric inspections. Visual inspections and physical measurements will detect changes in clearances, settings, and displacements associated with aging effects.

The removable core support structures in the reactor vessel require a VT-3 visual inspection in accordance with ASME Code Section XI, Table IWB-2500-1, Examination Category B-N-3 once every ISI interval.

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). Additionally, for a Condition Monitoring Program, the parameters monitored or inspected should detect the presence and extent of aging effects.

The staff finds that, where cracking is the physical evidence of the degradation mechanism that will affect the intended function of a given component, the inspections included in the program will be capable of directly detecting cracks. Where other parameters such as changes in clearances, settings, and displacements are associated with aging mechanisms, the staff finds the VT-3 visual inspections with physical measurements are acceptable methods to detect the presence and extent of an aging mechanism. The staff also noted that the applicant has committed to following the NRC-approved inspection and evaluation guidelines and the ASME Code Section XI ISI Program as well as submitting a detailed inspection plan for NRC approval either 2 years after the renewed license has been issued or 2 years before entering into the period of extended operation, whichever comes first. Based on these findings, the staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3; therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B.2.1.7 states that the applicant's program is based on the methodologies described in MRP-227, "Material Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines," where visual, surface, and volumetric exams are used to detect cracking and other aging mechanisms that could impact the intended function of internal components. All of the inspections are based on well-documented and frequently demonstrated examination procedures with which the industry has considerable experience. MRP-227 describes when inspections on internals should be performed (initial baseline and ongoing ISI on components in the primary category as well as expansion criteria), where the inspections should focus to find degradation in terms of sampling and coverage, and how the results of the inspections should be reported so that the industry is updated on any findings. In addition, the program identifies those components for which no additional measures are required because the existing AMPs—like the ASME Code, Section XI inspections—are capable of detecting the degradation before the loss of function of the component.

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 structure and component intended function(s). The criteria also states that parameters to be monitored or inspected should be appropriate to ensure that the structure and component 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 structure and component failure should not be considered as an 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.

In its review, the staff determined that cracking and general condition monitoring are appropriate parameters to monitor to ensure the maintenance of intended function of the components under consideration. The staff also determined that a combination of visual, surface, and volumetric test methods were capable of detecting cracks or other signs of damage related to degradation mechanisms, such as loss of preload or void swelling, prior to the loss of intended function. The staff additionally determined that the AMP refers to the NRC-approved, MRP-227 inspection and evaluation guidelines, and the ASME Code Section XI Code so that the specifications (how, where, when) for these inspections are explicitly stated.

Based on the above evaluation, the staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4; therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B.2.1.7 states that the program incorporates the inspection schedules and frequencies for the primary PWR internal components, in accordance with the NRC-approved, MRP-227 inspection and evaluation guidelines and the ASME Code Section XI ISI. If significant aging is detected in the primary components, the AMP also provides the procedures for disposition of any indications in accordance with the acceptance criteria and the threshold for and the scope of inspection expansion.

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 or industry-wide operating experience or both 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.

In this review, the staff determined that this program element adequately describes the monitoring and trending that is proposed. The staff also determined that the governing documents for the inspections to be monitored and trended provide sufficient guidance concerning inspection frequency and the modification of that frequency based on past inspections, or other plant-specific or industry operating experience, to provide timely corrective action or mitigation or additional inspections prior to loss of intended function. The staff further determined that the program element and the governing documents provided sufficient guidance to allow collected data to be compared to applicable acceptance standards.

Based on the above evaluation, the staff confirmed that the "monitoring and trending" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.5; therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B.2.1.7 states that acceptance criteria for this program are contained in the ASME Code, Section XI, Article IWB-3500, with additional guidance coming from the NRC-approved MRP-227. Detected conditions that do not meet the acceptance criteria will be dispositioned using the applicant's Corrective Action Program. Detected conditions that do meet the acceptance criteria will be documented as acceptable because the intended function of the component will be maintained 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 the acceptance criteria of the program and its basis should be described to include ensuring that the structure and component 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 structure and component 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.

In its review, the staff determined that the acceptance criteria for these inspections are clearly defined in the program element or in the governing documents. The staff also has no reason to believe that these values would not allow for the intended function of the components under consideration to be maintained during the period of extended operation under all CLB design loads.

Based on the above review, the staff confirmed that the "acceptance criteria" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.6; therefore, the staff finds it acceptable.

Operating Experience. LRA Section B.2.1.7 summarizes operating experience related to the PWR Vessel Internals Program. In this program element, the applicant stated that the previous ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program, Table IWB-2500-1, Category B-N-3 inspections for Seabrook RVIs, have not found any unacceptable indications. They will continue to participate in industry programs related to the aging effects on PWR vessel internals and will implement applicable results into their plant-specific AMP.

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.

The staff reviewed operating experience information, in the application and during the audit, to determine if 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 plant operating experience information to determine if the applicant adequately incorporated and evaluated operating experience related to this program.

During its review, the staff identified 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. The staff determined the need for additional clarification, which resulted in the issuance of RAI B.2.1.7-1, where the staff asked the applicant to do the following:

- list all the components in the Seabrook RPV internals that are fabricated from Alloy X-750
- discuss any plant-specific experience with components fabricated with Alloy X-750
- discuss how the plant will manage aging of the Alloy X-750 components

The applicant responded on January 13, 2011, by stating that the only components in the Seabrook RPV internals fabricated from Alloy X-750 are the clevis insert bolts identified in the UFSAR Table 5.2-4. When the plant began operation, the control rod drive mechanism (CRDM) guide tube support pins were fabricated from Alloy X-750. Subsequent industry experience showed that the Alloy X-750 CRDM support pins were susceptible to PWSCC. Based on the industry experience, Seabrook decided to replace these CRDM support pins during RFO 11 (October of 2006) with new, Westinghouse-designed CRDM support pins fabricated from cold worked stainless steel that demonstrated no susceptibility to PWSCC. Seabrook plans to manage the future age-related degradation for the clevis insert bolts by the implementation of MRP-227, "Material Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines," and the ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program requirements.

Based on its audit and review of the application, and review of the applicant's response to RAI B.2.1.7-1, 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; therefore, the staff finds the response acceptable and the issue resolved.

Based on this review, 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; therefore, the staff finds it acceptable.

UFSAR Supplement. LRA Section A.2.1.7 provides the UFSAR supplement for the PWR Vessel Internals AMP. The staff reviewed this UFSAR supplement description of the program and noted that it provides an adequate description of the program, as described in SRP-LR Section 3.6.3.4 and Table 3.6.2.

The staff noted that the applicant committed (LRA Section A.3, Commitment No. 1) to submit an inspection plan for RVIs for NRC review and approval at least 24 months prior to entering the period of extended operation. Since the LRA was submitted, the NRC completed its review of the MRP-227. In the safety evaluation, one of the plant-specific action items calls for each applicant to perform an evaluation of its plant's operating history, demonstrate the applicability of the approved version of MRP-227 to the facility, and submit this evaluation for NRC review and approval as part of its LRA to implement the approved version of MRP-227. For plants that have submitted their LRA, but have not received their renewed license, the NRC asked those plants to update their commitment to indicate that they will do the evaluation and create a plant-specific plan to implement the NRC-approved version within 24 months of receiving the renewed license or entering the period of extended operation, whichever comes first.

By letter dated April 22, 2011, the applicant provided an updated commitment (Commitment No. 01) to do the evaluation of the NRC-approved version of MRP-227 and create a plant-specific plan to implement the AMP within 24 months of receiving the renewed license or entering the period of extended operation, whichever comes first.

The staff determined that the information in the UFSAR supplement, as amended by the updated commitment, provided an adequate summary description of the program, as required by 10 CFR 54.21(d) and is, therefore, acceptable.

Conclusion. On the basis of its technical review of the applicant's PWR Vessel Internals Aging Management Program, the staff concludes that the applicant demonstrated that, through the use of this AMP, the effects of aging of the RVI components may be adequately managed so that the intended function(s) of the components under consideration 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 the Application

In Appendix A, "Updated 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 action, confirmation process, and administrative controls that are applied to the AMPs for both safety-related and nonsafety-related components. The FPL/NextEra Energy Quality Assurance Program (QAP) is used, which includes the elements of corrective action, 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. Appendix A, Section A.1.5 and Appendix B, Section B.1.3, of the LRA 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 NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (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. Of these 10 attributes, 3 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 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 Appendix A and Appendix B of the LRA, AMP basis documents, and the associated implementing procedures. The purpose of this review was to confirm 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 the staff's evaluation, the descriptions of the AMPs and their associated quality attributes provided in Appendix A, Section A.1.5, and Appendix B, Section B1.3, of the LRA are consistent with the staff's position regarding QA for aging management.

3.0.4.3 Conclusion

On the basis of the staff's evaluation, the descriptions and applicability of the plant-specific AMPs and their associated quality attributes provided in Appendix A, Section A.1.5, and Appendix B, Section B1.3 of the LRA, were determined to be 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).

3.0.5 Operating Experience

3.0.5.1 Summary of Technical Information in the Application

LRA Section B.1.4 describes the consideration of operating experience for AMPs. The LRA states that operating experience for existing programs and activities was reviewed as an input to the AMP evaluations.

This review included plant records, such as reports generated under the corrective action program, and was focused on degradation due to aging-related issues. The LRA also states that the operating experience review considered the results of plant-specific and industry operating experience and interviews with site personnel. Further, LRA Section 3.0.3 states that, "ongoing review of plant-specific and industry operating experience is performed in accordance with the plant Operating Experience Program and as a part of selected Seabrook Station aging management programs."

3.0.5.2 Staff Evaluation

The staff issued its final License Renewal Interim Staff Guidance LR-ISG-2011-05, "Ongoing Review of Operating Experience," dated March 16, 2012, which clarifies that AMPs should be informed, and enhanced when necessary, based on the ongoing review of both plant-specific and industry operating experience. Also, pursuant to 10 CFR 54.21(a)(3), an applicant is required to demonstrate that the effects of aging on systems, structures, and components subject to an AMR will be adequately managed so that its intended functions will be maintained consistent with the CLB for the period of extended operation. SRP-LR, Revision 2, Appendix A, describes 10 elements of an acceptable AMP. Section A.1.2.3.10 describes Element 10, "Operating Experience," as consisting of these three attributes:

1. Consideration of future plant-specific and industry operating experience relating to aging management programs should be discussed. Reviews of operating experience by the applicant in the future may identify areas where aging management programs should be enhanced or new programs developed. An applicant should commit to a future review of plant-specific and industry operating experience to confirm the effectiveness of its aging management programs or indicate a need to develop new aging management programs. This information should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the structure and component intended function(s) will be maintained during the period of extended operation.
2. Operating experience with existing programs should be discussed. The operating experience of AMPs that are existing programs, 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 managed adequately so that the structure- and component-intended function(s) will be maintained during the period of extended operation.
3. For new AMPs that have yet to be implemented at an applicant's facility, the programs have not yet generated any operating experience (OE). However, there may be other relevant plant-specific OE at the plant or generic OE in the industry that is relevant to the AMP's program elements even though the OE was not identified as a result of the implementation of the new program. Thus, for new programs, an applicant may need to consider the impact of relevant OE that results from the past implementation of its existing AMPs that are existing programs and the impact of relevant generic OE on developing the program elements. Therefore, operating experience applicable to new programs should be discussed. Additionally, an applicant should commit to a review of future plant-specific and industry operating experience for new programs to confirm its effectiveness.

SER Section 3.0.3 discusses the staff's review of the second and third attributes, which concern operating experience associated with existing and new programs, respectively. The evaluation below discusses the staff's review of the first attribute, which concerns the consideration of future operating experience and is applicable to both new and existing programs.

The staff reviewed LRA Sections B.1.4 and B.2.1.1 through B.2.3.2 to determine whether the applicant will implement adequate activities for the continual review of both plant-specific and industry operating experience to identify areas where AMPs should be enhanced or new AMPs developed. The staff determined that these LRA sections describe how the applicant incorporated operating experience into its AMPs, but they do not fully describe how the applicant will use future operating experience to ensure that the AMPs will remain effective for managing the aging effects during the period of extended operation. While the program descriptions contain statements indicating that future operating experience will be used to adjust the programs as appropriate, the details of this process are not fully described.

It was not clear to the staff whether the applicant intends to implement actions to monitor operating experience on an ongoing basis and use it to ensure the continued effectiveness of these AMPs. Further, the LRA does not state whether new AMPs will be developed, as necessary.

By letter dated December 12, 2011, the staff issued RAI B.1.4-2 requesting that the applicant describe in detail the programmatic activities that will be used to continually identify aging issues, evaluate them, and, as necessary, enhance the AMPs or develop new AMPs.

By letter dated January 20, 2012, the applicant provided its response to the staff's RAI. Subsequent to receipt of the applicant's response, the staff also issued its final License Renewal Interim Staff Guidance LR-ISG-2011-05, "Ongoing Review of Operating Experience." The staff is currently reviewing the applicant's response to determine its adequacy. This issue is identified as OI B.1.4-2.

3.0.5.3 UFSAR Supplement

The staff reviewed the UFSAR supplement in LRA Appendix A to determine whether the applicant provided an adequate summary description of the programmatic activities for the ongoing review of operating experience. As the staff found no such description, it also requested in RAI B.1.4-1 that the applicant provide a description of these activities for the UFSAR supplement required by 10 CFR 54.21(d).

In its response dated August 25, 2011, the applicant provided the following summary description of the operating experience review activities for the UFSAR supplement:

> The existing Corrective Action Program and the Operating Experience Program ensure, through the continual review of both plant-specific and industry operating experience, that the license renewal aging management programs are effective to manage the aging effects for which they are credited. The programs are either enhanced or new programs are developed when the review of operating experience indicates that the programs may not be effective. For each aging management program, operating experience is reviewed on a continuing basis.

The staff reviewed this UFSAR supplement description against the acceptance criteria in SRP-LR Sections 3.1.2.5, 3.2.2.5, 3.3.2.5, 3.4.2.5, 3.5.2.5, and 3.6.2.5. In accordance with these sections, the summary description should be sufficiently comprehensive such that later changes can be controlled by 10 CFR 50.59. With respect to these criteria, the staff determined that this summary description is not sufficiently comprehensive.

The applicant described generally how it intends to consider operating experience on an ongoing basis; however, it did not provide specific information on how its operating experience review activities address issues related to aging. Similarly, the above entry for UFSAR supplement also lacks detail on how aging is considered in the ongoing operating experience reviews. By letter dated December 12, 2011, the staff requested the applicant to clarify the UFSAR summary description provided in the applicant's letter dated August 25, 2011.

By letter dated January 20, 2012, the applicant provided its response to the staff's RAI. Subsequent to receipt of the applicant's response, the staff also issued its final License Renewal Interim Staff Guidance LR-ISG-2011-05, "Ongoing Review of Operating Experience." The staff is currently reviewing the applicant's response to determine its adequacy. This issue is identified as OI B.1.4-2.

3.0.5.4 Conclusion

The staff's conclusion regarding the applicant's programmatic activities for the ongoing review of operating experience is pending resolution of the OI B.1.4-2.

3.1 <u>Aging Management of Reactor Coolant System</u>

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:

- RCS
- reactor vessel
- RVIs
- steam generator

3.1.1 Summary of Technical Information in the Application

LRA Section 3.1 provides AMR results for the RCS, reactor vessel, RVIs, and steam generator. 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, RVIs, and steam generator 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 if the applicant provided sufficient information to demonstrate that the effects of aging for the RCS, reactor vessel, RVIs, and steam generator 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 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 Section 3.1.2.1.

The staff 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 3.1.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 3.1.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the specified material-environment combinations. Details of the staff's evaluation are presented in SER Section 3.1.2.3.

For components that the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR 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	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Steel; stainless steel; steel with Ni-alloy or stainless steel cladding; Ni-alloy RV 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 addressed for Class 1 components	Yes	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Steel; stainless steel; steel with Ni-alloy or stainless steel cladding; Ni-alloy RCPB 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 addressed for Class 1 components	Yes	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Steel pump and valve closure bolting (3.1.1-4)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and Code limits checked for allowable cycles (less than 7,000 cycles) of thermal stress range	Yes	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Stainless steel and Ni-alloy RVI components (3.1.1-5)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA, evaluated in accordance with 10 CFR 54.21(c)	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
Ni-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	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Fatigue is a TLAA (See SER Section 3.1.2.2.1)
Steel and stainless steel RCPB 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	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Fatigue is a TLAA (See SER Section 3.1.2.2.1)
Steel; stainless steel; Ni-alloy RCPB piping, piping components, piping elements; flanges; nozzles and safe ends; pressurizer vessel shell heads and welds; heater sheaths and sleeves; penetrations; thermal sleeves (3.1.1-8)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects addressed for Class 1 components	Yes	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects addressed for Class 1 components	Fatigue is a TLAA (See SER Section 3.1.2.2.1)
Steel; stainless steel; steel with Ni-alloy or stainless steel cladding; Ni-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 addressed for Class 1 components	Yes	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects addressed for Class 1 components	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
Steel; stainless steel; steel with Ni-alloy or stainless steel cladding; Ni-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 addressed for Class 1 components	Yes	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects addressed for Class 1 components	Fatigue is a TLAA (See SER Section 3.1.2.2.1)
Steel top head enclosure (without cladding) and top head nozzles (vent, top head spray, or reactor core isolation cooling, 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	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
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	Once-through steam generator (OTSG) only	Applicable to OTSGs, therefore, not applicable to Seabrook (See SER Section 3.1.2.1.1)
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	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Stainless steel; Ni alloy; steel with Ni-alloy or stainless steel cladding RV 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	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Stainless steel; steel with Ni-alloy or stainless steel cladding; Ni-alloy RCPB 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	Not applicable	Not applicable to PWRs (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
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	ISI (IWB, IWC, and IWD) and Water Chemistry. For Westinghouse Model 44 and 51 steam generators, if general and pitting corrosion of the shell is known to exist, additional inspection procedures are to be developed.	Yes	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program; Water Chemistry Program; and Steam Generator Tube Integrity Program	Consistent with the GALL Report (See SER Section 3.1.2.2.2)
Steel (with or without stainless steel cladding) RV beltline shell, nozzles, and welds (3.1.1-17)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, evaluated in accordance with Appendix G of 10 CFR Part 50 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, evaluated in accordance with 10 CFR 54.21(c), Appendix G of 10 CFR 50, and RG 1.99	Loss of fracture toughness due to neutron irradiation is a TLAA (See SER Section 3.1.2.2.3)
Steel (with or without stainless steel cladding) RV 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	RV Surveillance Program	Consistent with the GALL Report (See SER Section 3.1.2.2.3)
Stainless steel and Ni-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	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Stainless steel isolation condenser components exposed to reactor coolant (3.1.1-20)	Cracking due to SCC and IGSCC	ISI (IWB, IWC, and IWD), Water Chemistry, and plant-specific verification program	Yes	Not applicable	Not applicable to PWRs (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
RV 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—Seabrook's RV shell is not fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process.	Not applicable to Seabrook (See SER Section 3.1.2.2.5)
Stainless steel and Ni-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 participate in industry RVI aging programs; implement applicable results; and submit for staff approval, greater than 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	No	PWR Vessel Internals Program	Consistent with the GALL Report (See SER Section 3.1.2.2.6)
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	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program	Consistent with the GALL Report (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	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program, and Water Chemistry Program	Consistent with the GALL Report (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 PWRs (See SER Section 3.1.2.1.1)
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-26)	Cracking due to cyclic loading	ISI (IWB, IWC, and IWD) and plant-specific verification program	Yes	Not applicable	Not applicable to PWRs (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 Ni-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 staff approval, greater than 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	No	PWR Vessel Internals Program	Consistent with the GALL Report (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 to Seabrook	Not applicable to Seabrook (See SER Section 3.1.2.2.10)
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	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Stainless steel RVI components (e.g., upper internals assembly, rod cluster control assembly guide tube assemblies, baffle/former assembly, lower internal assembly, shroud assemblies, plenum cover and plenum cylinder, upper grid assembly, control rod guide tube 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 IASCC	Water Chemistry and UFSAR supplement commitment to: (1) participate in industry, RVI aging programs; (2) implement applicable results; and (3) submit for staff approval, greater than 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	No	PWR Vessel Internals and Water Chemistry programs	Consistent with the GALL Report (See SER Section 3.1.2.2.12)

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
Ni alloy and steel with Ni-alloy cladding piping, piping component, piping elements, penetrations, nozzles, safe ends, and welds (other than RV head); pressurizer heater sheaths, sleeves, diaphragm plate, manways, and flanges; core support pads/core guide lugs (3.1.1-31)	Cracking due to PWSCC	ISI (IWB, IWC, and IWD) and Water Chemistry and UFSAR supplement commitment to implement applicable plant commitments to NRC Orders, bulletins, and GLs associated with Ni alloys and staff-accepted industry guidelines.	No	ASME Code Section XI ISI Subsections IWB, IWC, and IWD Program, Nickel-Alloy Nozzles and Penetrations Program, and the Water Chemistry Program	Consistent with the GALL Report (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	Steam Generator Tube Integrity Program	Consistent with GALL Report (See SER Section 3.1.2.2.14)
Stainless steel and Ni-alloy RVI components (3.1.1-33)	Changes in dimensions due to void swelling	UFSAR supplement commitment to participate in industry RVI aging programs; implement applicable results; and submit for staff approval, greater than 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	No	PWR Vessel Internals Program	Consistent with the GALL Report (See SER Section 3.1.2.2.15)
Stainless steel and Ni-alloy reactor control rod drive (CRD) head penetration pressure housings (3.1.1-34)	Cracking due to SCC and PWSCC	ISI (IWB, IWC, and IWD) and Water Chemistry. For Ni alloy, UFSAR supplement commitment to implement applicable plant commitments to NRC Orders, bulletins, and GLs associated with Ni alloys and staff-accepted industry guidelines.	No	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report (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 Ni-alloy cladding primary side components; steam generator upper and lower heads; tubesheets; and tube-to-tubesheet welds (3.1.1-35)	Cracking due to SCC and PWSCC	ISI (IWB, IWC, and IWD) and Water Chemistry. For Ni alloy, UFSAR supplement commitment to implement applicable plant commitments to NRC Orders, bulletins, and GLs associated with Ni alloys and staff-accepted industry guidelines.	No	Submit plant-specific AMP to manage tube-tubesheet welds at least 24 months prior to the period of extended operation (Commitment No. 54)	Applicable to OTSGs; therefore, not applicable to Seabrook except for tube-to-tubesheet welds between Ni-alloy cladding and Ni-alloy tubes in the steam generator (see SER Section 3.1.2.2.16)
Ni-alloy, stainless steel pressurizer spray head (3.1.1-36)	Cracking due to SCC and PWSCC	Water Chemistry and One-Time Inspection. For Ni-alloy welded spray heads, provide commitment in UFSAR supplement to submit AMP delineating commitments to NRC Orders, bulletins, or GLs that inspect stipulated components for cracking of wetted surfaces.	No	One-Time Inspection and Water Chemistry Programs	Consistent with the GALL Report (See SER Section 3.1.2.2.16)
Stainless steel and Ni-alloy RVI components (e.g., upper internals assembly, rod cluster control assembly 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 participate in industry RVI aging programs; implement applicable results; and submit for staff approval, greater than 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	No	The PWR Vessel Internals Program and the Water Chemistry Program, including Commitment No. 01	Consistent with the GALL Report (See SER Section 3.1.2.2.17)

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) CRD return line nozzles exposed to reactor coolant (3.1.1-38)	Cracking due to cyclic loading	BWR CRD Return Line Nozzle	No	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
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	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Stainless steel and Ni-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	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Stainless steel and Ni-alloy piping, piping components, and piping elements ≥ 4″ nominal pipe size (NPS); nozzle safe ends and associated welds (3.1.1-41)	Cracking due to SCC and IGSCC	BWR SCC and Water Chemistry	No	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Stainless steel and Ni-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	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Stainless steel fuel supports and CRD assemblies and CRD housing exposed to reactor coolant (3.1.1-43)	Cracking due to SCC and IGSCC	BWR Vessel Internals and Water Chemistry	No	Not applicable	Not applicable to PWRs (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 Ni-alloy core shroud, core plate, core plate bolts, support structure, top guide, core spray lines, spargers, jet pump assemblies, CRD housing, and nuclear instrumentation guide tubes (3.1.1-44)	Cracking due to SCC, IGSCC, and IASCC	BWR Vessel Internals and Water Chemistry	No	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
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	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Ni-alloy core shroud and core plate access hole cover (mechanical covers) (3.1.1-46)	Cracking due to SCC, IGSCC, and IASCC	ISI (IWB, IWC, and IWD), and Water Chemistry	No	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Stainless steel and Ni-alloy RVIs exposed to reactor coolant (3.1.1-47)	Loss of material due to pitting and crevice corrosion	ISI (IWB, IWC, and IWD) and Water Chemistry	No	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Steel and stainless steel Class 1 piping, fittings, and branch connections < 4″ NPS exposed to reactor coolant (3.1.1-48)	Cracking due to SCC, IGSCC (for stainless steel only), and thermal and mechanical loading	ISI (IWB, IWC, and IWD) Water chemistry, and One-Time Inspection of ASME Code Class 1 Small-Bore Piping	No	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
Ni-alloy core shroud and core plate access hole cover (welded covers) (3.1.1-49)	Cracking due to SCC, IGSCC, and IASCC	ISI (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	Not applicable	Not applicable to PWRs (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
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	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
CASS jet pump assembly castings and 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	Not applicable	Not applicable to PWRs (See SER Section 3.1.2.1.1)
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 Program	Consistent with the GALL Report
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	Closed-Cycle Cooling Water System Program	Consistent with the GALL Report
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 Seabrook (See SER Section 3.1.2.1.1)
CASS Class 1 pump casings and valve bodies and bonnets exposed to reactor coolant > 482 °F (250 °C) (3.1.1-55)	Loss of fracture toughness due to thermal aging embrittlement	ISI (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 Code Section XI ISI, Subsections IWB, IWC, and IWD Program	Consistent with 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
Copper-alloy > 15% 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 Seabrook (See SER Section 3.1.2.1.1)
CASS Class 1 piping, piping components, and piping elements and CRD pressure housings exposed to reactor coolant > 482 °F (250 °C) (3.1.1-57)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Not applicable	Not applicable to Seabrook (See SER Section 3.1.2.1.1)
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	Boric Acid Corrosion Program	Consistent with the GALL Report
Steel steam generator steam nozzle and safe end, feedwater nozzle and safe end, auxiliary feedwater nozzles and safe ends exposed to secondary feedwater/steam (3.1.1-59)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Flow-Accelerated Corrosion Program	Consistent with the GALL Report
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 Seabrook (See SER Section 3.1.2.1.1)
Stainless steel and steel pressurizer integral support exposed to air with metal temperature up to 550 °F (288 °C) (3.1.1-61)	Cracking due to cyclic loading	ISI (IWB, IWC, and IWD)	No	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program	Consistent with the GALL Report
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	ISI (IWB, IWC, and IWD)	No	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program	Consistent with 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 reactor vessel flange and stainless steel and Ni-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, and lower grid assembly) (3.1.1-63)	Loss of material due to wear	ISI (IWB, IWC, and IWD)	No	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program	Consistent with the GALL Report
Stainless steel and steel with stainless steel or Ni-alloy cladding pressurizer components (3.1.1-64)	Cracking due to SCC and PWSCC	ISI (IWB, IWC, and IWD) and Water Chemistry	No	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report
Ni-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	ISI (IWB, IWC, and IWD) and Water Chemistry and Ni-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	No	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program, Nickel-Alloy Penetration Nozzles Welded to the Upper RV Closure Heads of PWRs Program, and Water Chemistry Program	Consistent with the GALL Report
Steel steam generator secondary manways and handholds (cover only) exposed to air with leaking secondary-side water or steam or both (3.1.1-66)	Loss of material due to erosion	ISI (IWB, IWC, and IWD) for Class 2 components	No	Not applicable	Not applicable to Seabrook, applicable to OTSGs (See SER Section 3.1.2.1.1)
Steel with stainless steel or Ni-alloy cladding or stainless steel pressurizer components exposed to reactor coolant (3.1.1-67)	Cracking due to cyclic loading	ISI (IWB, IWC, and IWD) and Water Chemistry	No	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with 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
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	ISI (IWB, IWC, and IWD) and Water Chemistry	No	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program, and Water Chemistry Program	Consistent with the GALL Report
Stainless steel, Ni-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	ISI (IWB, IWC, and IWD) and Water Chemistry	No	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report (See SER Section 3.1.2.1.2)
Stainless steel; steel with stainless steel cladding Class 1 piping, fittings, and branch connections < 4″ NPS exposed to reactor coolant (3.1.1-70)	Cracking due to SCC and thermal and mechanical loading	ISI (IWB, IWC, and IWD), Water Chemistry, and One-Time Inspection of ASME Code Class 1 Small-Bore Piping	No	ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program, Water Chemistry Program, and One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program	Consistent with the GALL Report
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	Reactor Head Closure Studs Program	Consistent with 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
Ni-alloy steam generator tubes and sleeves exposed to secondary feedwater/steam (3.1.1-72)	Cracking due to outside-diameter stress corrosion cracking and intergranular attack and loss of material due to fretting and wear	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Tube Integrity Program and Water Chemistry Program	Consistent with the GALL Report
Ni-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	Steam Generator Tube Integrity Program and Water Chemistry Program	Consistent with the GALL Report
Chrome plated steel, stainless steel, Ni-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	Steam Generator Tube Integrity Program and Water Chemistry Program	Consistent with the GALL Report
Ni-alloy 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 Seabrook, applicable to OTSGs (See SER Section 3.1.2.1.1)
Steel steam generator tube support plate and 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	Steam Generator Tube Integrity Program and Water Chemistry Program	Consistent with the GALL Report Ligament cracking due to corrosion is not applicable to the tube support plates since they are stainless steel (See SER Section 3.1.2.1.1)
Ni-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 (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
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 (See SER Section 3.1.2.1.1)
Ni-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 and Water Chemistry. 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 Bulletin 88-02.	No	Not applicable	Not applicable (See SER Section 3.1.2.1.1)
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 (See SER Section 3.1.2.1.2)
Ni alloy or Ni-alloy clad steam generator divider plate exposed to reactor coolant (3.1.1-81)	Cracking due to PWSCC	Water Chemistry	No	Water Chemistry Program and one-time inspection of SG divider plates	Consistent with the GALL Report (See SER Section 3.1.2.1)
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 Seabrook, (See SER Section 3.1.2.1.1)
Stainless steel; steel with Ni-alloy or stainless steel cladding; Ni-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	Water Chemistry Program	Consistent with 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
Ni-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 ISI (IWB, IWC, and IWD)	No	Not applicable	Not applicable to Seabrook, applicable to OTSGs (See SER Section 3.1.2.1.1)
Ni-alloy piping, piping components, and piping elements exposed to air-indoor uncontrolled (external) (3.1.1-85)	None	None	No	None	Consistent with the 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 the GALL Report
Steel piping, piping components, and piping elements in concrete (3.1.1-87)	None	None	No	Not applicable	Not applicable to Seabrook (See SER Section 3.1.2.1.1)

The staff's review of the RCS component groups followed one of several approaches. One approach, documented in SER Section 3.1.2.1, discusses the staff's review of 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 3.1.2.2, discusses the staff's review of 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 3.1.2.3, discusses the staff's review of 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 RCS components is documented in SER Section 3.0.3.

3.1.2.1 Aging Management Review 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 RCS, reactor vessel, RVIs, and steam generator components:

- ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Program
- External Surfaces Monitoring Program
- Flow-Accelerated Corrosion Program
- Nickel-Alloy Nozzles and Penetrations Program
- Nickel-Alloy Penetration Nozzles Welded to the Upper RV Closure Heads of PWRs Program
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program
- One-Time Inspection Program
- PWR Vessel Internals Program
- Reactor Head Closure Studs Program
- Reactor Vessel Surveillance Program
- Steam Generator Tube Integrity Program
- Water Chemistry Program

LRA Tables 3.1.2-1 through 3.1.2-4 summarize the results of AMRs for the RCS, reactor vessel, RVIs, and steam generator components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine if 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 item describing how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with Notes A–E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR 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 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 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 items to verify consistency with the GALL Report and to ensure 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 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 items to verify consistency with the GALL Report. The staff also determined whether the AMR 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 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 items to verify consistency with the GALL Report. The staff confirmed whether the AMR item of the different component was applicable to the component under review and whether the exceptions to the GALL Report AMPs was 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 item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff reviewed these 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 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.

LRA Table 3.1.1, item 3.1.1-81, addresses nickel alloy or nickel-alloy clad steam generator divider plates exposed to reactor coolant, which are being managed for cracking due to primary water stress corrosion cracking (PWSCC). The LRA credits the Water Chemistry Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," to ensure that this aging effect is adequately managed.

In its review of components associated with item 3.1.1-81, for which the applicant cited generic note A, the staff noted that, subsequent to the publication date of GALL Report Revision 1 (September 2005), foreign operating experience in steam generators with a similar design to that of the applicant's steam generators found cracking due to PWSCC in the steam generator divider plate assemblies made of Alloy 600, even with proper primary water chemistry. Specifically, cracks were detected in the stub runner, very close to the tubesheet/stub runner weld and with depths of almost a third of the divider plate thickness. Therefore, the staff noted that the Water Chemistry Program, alone, may not be effective in managing cracking due to PWSCC in steam generator divider plate assemblies.

The staff further noted that, based on the foreign steam generator divider plate experience, the domestic PWR industry has issued technical studies, such as EPRI report 1014982, "Divider Plate Cracking in Steam Generators—Results of Phase 1: Analysis of Primary Water Stress Corrosion Cracking and Mechanical Fatigue in the Alloy 600 Stub Runner to Divider Plate Weld Material," June 2007, to address cracking due to PWSCC for nickel-alloy divider plates and potential for propagation of divider plate cracks into other adjacent components.

By letter dated December 14, 2010, the staff issued RAI B.2.1.10-2 requesting that the applicant discuss the materials of construction for its steam generator divider plate assemblies and the susceptibility of its divider plate assemblies to cracking. The staff also asked the applicant to describe an inspection program to ensure that there are no cracks that could propagate into and challenge the integrity of other components that are part of the RCPB (e.g., tube sheet and channel head).

Details of the applicant's response to RAI B.2.1.10-2 and the staff's evaluation of that response are documented in SER Section 3.0.3.2.2. In its response, the applicant stated that it has Westinghouse Model F steam generators, and the steam generators' divider plates and weld materials are Inconel (ASME-SB-168) Alloy 600/82/182. The applicant further stated that it will perform an inspection of each steam generator, including a one-time inspection of the divider plate assemblies, prior to entering the period of extended operation and that any evidence of divider plate cracking will be documented and evaluated under the Corrective Action Program. The applicant also stated that the inspection techniques used will be capable of detecting PWSCC in the steam generator divider plate assemblies and their associated welds. The applicant committed (Commitment No. 55) that, prior to entering the period of extended operation, it will perform inspections of each steam generator, including the one-time inspection of divider plate assemblies.

The staff's evaluation of the applicant's response to RAI B.2.1.10-2 is documented in SER Section 3.0.3.2.2, and Open Item OI 3.0.3.2.2-1 was identified for the applicant to provide additional information regarding its one-time inspection of the divider plate assembly in its UFSAR Supplement. Resolution for OI 3.0.3.2.2-1 will be documented in Section 3.0.3.2.2.

3.1.2.1.1 Aging Management Review Results Identified as Not Applicable

Based on its initial review, the staff identified several items of LRA Table 3.1.1 in which the applicant stated the items were not applicable to Seabrook. This subsection discusses the evaluation of those items.

LRA Table 3.1.1, items 3.1.1-1, 3.1.1-2, 3.1.1-3, 3.1.1-4, 3.1.1-11, 3.1.1-13, 3.1.1-14, 3.1.1-15, 3.1.1-19, 3.1.1-20, 3.1.1-25, 3.1.1-26, 3.1.1-29, 3.1.1-38, 3.1.1-39, 3.1.1-40, 3.1.1-41, 3.1.1-42, 3.1.1-43, 3.1.1-44, 3.1.1-45, 3.1.1-46, 3.1.1-47, 3.1.1-48, 3.1.1-49, 3.1.1-50, and 3.1.1-51 discuss the applicant's determination on GALL Report AMR items that are applicable only to BWR-designed reactors. In the applicant AMR discussions for these items, no additional information is provided. The staff confirmed that these AMR items in Table 1 of the GALL Report, Volume 1, are only applicable to BWR-designed reactors and that Seabrook is a PWR with a dry ambient containment. Based on this determination, the staff finds that the applicant provided an acceptable basis for concluding AMR items 3.1.1-1, 3.1.1-2, 3.1.1-3, 3.1.1-4, 3.1.1-11, 3.1.1-13, 3.1.1-14, 3.1.1-15, 3.1.1-19, 3.1.1-20, 3.1.1-25, 3.1.1-26, 3.1.1-29, 3.1.1-38, 3.1.1-39, 3.1.1-40, 3.1.1-41, 3.1.1-42, 3.1.1-43, 3.1.1-44, 3.1.1-45, 3.1.1-46, 3.1.1-47, 3.1.1-48, 3.1.1-49, 3.1.1-50, and 3.1.1-51 in Table 1 of the GALL Report, Volume 1, are not applicable to Seabrook.

LRA Table 3.1.1, items 3.1.1-12, 3.1.1-66, 3.1.1-75, and 3.1.1-84 discuss the applicant's determination on GALL Report AMR items that are applicable only to once-through steam generators (OTSGs). The staff confirmed that these AMR items in Table 1 of the GALL Report, Volume 1, are only applicable to OTSGs and confirmed, by reviewing various sections of the LRA and UFSAR, that Seabrook has recirculating steam generators. Based on this determination, the staff finds that the applicant provided an acceptable basis for concluding AMR items 12, 35, 66, 75, and 84 in Table 1 of the GALL Report, Volume 1, are not applicable to Seabrook.

LRA Table 3.1.1, item 3.1.1-35 addresses cracking due to stress corrosion cracking (SCC) and PWSCC in steel with stainless steel or Ni-alloy cladding primary side components and steam generator upper and lower heads, tubesheets, and tube-to-tubesheet welds. The staff confirmed, with one exception noted below, that this AMR item in Table 1 of the GALL Report, Volume 1, is only applicable to OTSGs, and confirmed, by reviewing various sections of the LRA and the UFSAR, that Seabrook has recirculating steam generators. Based on this determination, the staff finds that the applicant provided an acceptable basis for concluding AMR item 35 in Table 1 of the GALL Report, Volume 1, is not applicable to Seabrook with one exception—the tube-to-tubesheet welds for the steam generators. This issue is discussed and resolved in SER Section 3.1.2.2.16.1.

LRA Table 3.1.1, item 3.1.1-54 addresses the loss material due to pitting, crevice, and galvanic corrosion of copper-alloy piping, piping components, and piping elements exposed to closed-cycle cooling water. The applicant stated that these items are not applicable to Seabrook because there are no copper-alloy components exposed to closed-cycle cooling water in the RCS, RC, RVIs, or steam generator.

The staff reviewed the LRA and the UFSAR and concludes that the applicant does not have any AMR results that are applicable for this item.

LRA Table 3.1.1, item 3.1.1-56 addresses copper-alloy (with greater than 15 percent Zn) piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water. The GALL Report recommends the use of GALL Report AMP XI.M33, “Selective Leaching of Materials,” to manage loss of material due to selective leaching for this component group. The applicant stated that this item is not applicable because there are no RCS components fabricated from copper alloy greater than 15 percent Zn and exposed to closed-cycle cooling water.

The staff reviewed the LRA and the UFSAR and concludes that the applicant does not have any AMR results that are applicable for this item.

LRA Table 3.1.1, item 3.1.1-57 describes the aging effect in cast austenitic stainless steel (CASS) Class 1 piping, piping components, piping elements, and CRD pressure housings exposed to reactor coolant greater than 482 °F (250 °C). The applicant stated that the RCS has fittings made of SA-351 Grade CF8A material with service conditions greater than 482 °F. Additionally, the aging effect in the GALL Report for this material and environment combination is not applicable because the molybdenum and ferrite contents for these components are below the industry-accepted thresholds for loss of fracture toughness due to thermal aging embrittlement.

The staff reviewed the LRA and the UFSAR and concludes that the applicant does not have any AMR results that are applicable for this item.

LRA Table 3.1.1, item 3.1.1-60, addresses loss of material due to wear for stainless steel flux thimble tubes (with or without chrome plating) exposed to reactor coolant. The applicant stated that this item is not applicable because it uses a double-concentric thimble tube design fabricated from wear-resistant, seamless nickel-alloy material (Inconel 600).

The staff noted that GALL Report AMR item IV.B2-13 recommends GALL Report AMP XI.M37, “Flux Thimble Tube Inspection,” to manage the loss of material due to wear for stainless steel flux thimble tubes (with or without chrome plating). However, the GALL Report does not include a generic AMR item for the management of loss of material due to wear in nickel-alloy flux thimble tubes. The "detection of aging effects" program element in GALL Report AMP XI.M37 states that, for Westinghouse design flux thimble tubes, if design changes are made to use more wear-resistant thimble tube materials (e.g., chrome-plated stainless steel), sufficient inspections will be conducted at an adequate inspection frequency for the new materials. In addition, the staff also noted that LRA Table 3.1.2-3 includes an AMR item to manage cracking in the nickel-alloy flux thimble tubes. The applicant credited its PWR Vessel Internals Program and Water Chemistry Program to manage cracking. The applicant's PWR Vessel Internals Program is described in LRA Section B.2.1.7 and is based on recommendations in "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 0)." The staff reviewed MRP-227, Revision 0 and noted that it does not include guidance for managing cracking of flux thimble tubes.

By letter dated January 5, 2011, the staff issued RAI 3.1.1-60-01 requesting that the applicant justify not including an applicable AMR item to manage loss of material due to wear in the nickel-alloy flux thimble tubes. The staff also asked the applicant to justify why a Flux Thimble Tube Inspection Program is not credited to manage loss of material due to wear for these components.

In addition, the staff also issued RAI 3.1.1-60-02, by letter dated January 5, 2011, requesting that the applicant justify its crediting of the PWR Vessel Internals Program to manage cracking in flux thimble tubes, considering that MRP-227, Revision 0 does not contain recommendations for managing cracking in Westinghouse-design flux thimble tubes.

In its response to RAI 3.1.1-60-01, by letter dated February 3, 2011, the applicant stated that its design is unique and can accommodate both fixed and movable incore detectors housed, respectively, in the outer and inner tubes of the double-concentric thimble tube design. The applicant also stated that since its Operating Cycle 5, the movable incore detectors have not been used and were placed into a lay-up condition during RFO 7 (fall of 2000). The applicant also stated that since RFO 7, as part of a design change, "Movable Incore Detector System Lay-up," the seal table tubing between the inner calibration tubing and the isolation valves has been removed, and the inner calibration tubing has been capped. The applicant further stated that, based on the unique design features of the incore detector, the aging effects managed by GALL Report AMP XI.M37 do not apply. The staff found the applicant's response inadequate because, per the plant's licensing basis (License Amendment No. 27 (ML011870008)), the applicant is allowed and has the option to place the movable incore detectors back in service, putting the inner tubes in a condition that is susceptible to wear.

In its response to RAI 3.1.1-60-02, by letter dated February 3, 2011, the applicant stated that the design change has disconnected the movable detector and has installed a qualified pressure-retaining cap. The applicant further stated that flux thimble tubes do not have a license renewal-intended RCPB function. For this reason, the applicant subsequently deleted the pressure boundary function for these thimble tubes from LRA Table 2.3.1-3 and the AMR items on cracking of these thimble tubes from the scope of LRA Table 3.1.2-3. The staff also found this response inadequate because it did not change the staff's previously stated concern that, per the plant's licensing basis, the applicant still has the option to place the movable incore detectors back in service, putting the inner tubes in a condition that is susceptible to wear as well as making it a pressure boundary.

By letter dated March 30, 2011, the staff issued an additional followup RAI 3.1.1-60-01/02 to request that the applicant further justify why an AMP is not required to manage loss of material due to wear of the inner tube flux thimble tubes during the period of extended operation if the movable detectors were placed back into service. In addition, the staff also asked the applicant to justify its deletion of the AMR items associated with cracking of the flux thimble tubes from LRA Table 3.1.2-3.

To resolve the staff's concern that the applicant would place the movable incore detectors back in service, the applicant submitted its response to followup RAI 3.1.1-60-01/02, dated April 22, 2011, committing to implement measures prior to entering the period of extended operation to ensure that the movable detectors are not returned to service during the period of extended operation (Commitment No. 65). In addition, as part of its response, the applicant provided a drawing illustrating the design of the incore detector assembly. The applicant stated that when the incore detector assembly is inserted, the thimble housing tube (outer tube) provides the RCPB. The applicant also stated that the thimble calibration tube (inner tube), although considered an RCPB, is not in actual contact with reactor coolant. The applicant stated that the original fixed incore detector assemblies were not designed for the life of the plant, and, therefore, a replacement program was developed. For the replacement detector thimble assemblies, the inner tubes are solid from the seal table to below the core support plate. The applicant also stated that it plans to replace all 58 incore detector assemblies using the improved design. The applicant further stated that the plant’s technical specifications (TSs) require performance of an incore/excore comparison every 31 effective full power days (EFPD) when the power level is greater than 50 percent and an incore/excore calibration every 92 EFPD when power is greater than 75 percent.

Following review of the applicant’s response to followup RAI 3.1.1-60-01/02, the staff needed further clarification as to where exactly the RCS pressure boundary is for the applicant’s replacement detector assemblies and the original capped detector assemblies. Therefore, by letter dated October 7, 2011, the staff issued followup RAI 3.1.1-60-02, requesting that the applicant verify the RCS pressure boundary for the replacement and original capped incore detector assemblies.

In its response to followup RAI 3.1.1-60-02, dated November 2, 2011, the applicant stated that for the original incore detector assembly design, the RCS pressure boundary consists of the reactor vessel bottom instrument penetration, the incore instrument guide tube, the high pressure instrument connection, the portion of the calibration tube that extends above the high pressure instrument connection, and the pressure-retaining cap. The applicant also stated that for replacement incore detector assembly design, the RCS pressure boundary consists of the reactor vessel bottom instrument penetration, the incore instrument guide tube, and the high pressure instrument connection. As part of its response, the applicant revised LRA Table 3.1.2-1 and added three additional AMR Items under component type “Calibration Tube,” on page 3.1-44 of the LRA. In addition, as part of its response, the applicant also revised the boundary description on page 2.3-5 of the LRA to reflect its response to followup RAI 3.1.1-60-02.

Based on its review, the staff finds the applicant’s response to followup RAI 3.1.1-60-02 acceptable because the applicant has revised LRA sections related to its flux thimble tubes in order to include portions of the incore detector assemblies that constitute the RCS pressure boundary and are subject to an AMR per 10 CFR 54.21(a)(1). The staff evaluated the applicant’s revisions to LRA Tables 3.1.1 and 3.1.2-1 and finds that for the portion of the applicant’s flux thimble assemblies that constitute the RCS pressure boundary, there are no applicable aging effects. Specifically, the staff noted that two of the AMR items added correspond to NUREG-1801, Volume 2, item IV.E-1(RP-03), for which the aging effect is consistent with the applicant's disposition of Note A. For the third AMR item added, the applicant cited Note G and plant-specific note 1. Plant-specific note 1 states the following:

> NUREG-1801 does not include air with borated water leakage for nickel-alloy components. Similar to V.F-13 for stainless steel, there are no aging effects for nickel alloy in air with borated water leakage. Additionally, the American Welding Society (AWS) "Welding Handbook," (Seventh Edition, Volume 4, 1982, Library of Congress) identifies that nickel chromium alloy materials that are alloyed with iron, molybdenum, tungsten, cobalt or copper in various combinations have improved corrosion resistance.

The staff reviewed the associated item and confirmed that the applicant's use of generic note G for this item is appropriate in that the GALL Report, Revision 1 does not include entries for nickel-alloy components exposed to air with borated water leakage. The staff noted that the GALL Report, Revision 2, dated December 2010, includes entries for nickel-alloy components exposed to air with borated water leakage. These entries indicate that no aging effect requiring management is present for this material-environment combination. The staff also noted that these AMR items in the GALL Report, Revision 2 are based in part on EPRI Report 1000975, "Boric Acid Corrosion Guidebook, Revision 1." This report contains data (pages 4–43) showing that "[t]here was no measurable corrosion of stainless steel piping surfaces or Inconel weld metal joining the stainless steel and carbon steel piping sections." The staff, therefore, finds the applicant's identification of aging effects for these components to be acceptable.

The staff also finds that the design modifications, and the applicant's commitment (Commitment No. 65) that the movable detectors will not be returned to service during the period of extended operation, eliminate the possibility of wear and RCS pressure boundary leakage through the prior movable detector dry path. Therefore, the staff's concerns described in RAIs 3.1.1-60-01, 3.1.1-60-02, and followup RAI 3.1.1-60-01/02 are resolved.

The staff noted that applicant's current and replacement incore detector assemblies are sufficiently different from the standard Westinghouse designed thimble tubes for movable detectors, in that:

- Failure of both the inner and outer flux thimble tubes inside of the reactor vessel, either due to wear or cracking, would not result in an RCS pressure boundary leakage.
- The applicant's capping and replacement program with the solid inner tubes has eliminated the possibility of RCS pressure boundary leakage through the prior movable detector dry path.
- Wear will not initiate in the inner tubes based on the placement of the applicant's commitment (Commitment No. 65).
- Periodic monitoring of the flux detectors would ensure that aging effects are detected prior to loss of intended function(s) as part of the applicant's technical specifications.

Therefore, the staff finds that the applicant has provided an acceptable basis that a Flux Thimble Tube Inspection Program is not needed to manage wear or cracking of the applicant's flux thimble tubes.

LRA Table 3.1.1, item 3.1.1-76 addresses, in part, ligament cracking due to corrosion of steel tube support plates exposed to secondary feedwater or steam. The applicant stated that such ligament cracking is not applicable because its tube support plates are made of stainless steel.

The staff reviewed the steam generator description in LRA Section 2.3.1.4 and UFSAR Section 5.4 in order to verify the design of the plant's steam generators and confirmed that the applicant's steam generators (Westinghouse Model F steam generators) have tube support plates made of stainless steel. Therefore, the staff finds that this item is not applicable.

LRA Table 3.1.1, item 3.1.1-77 addresses the loss of material due to wastage and pitting corrosion in Ni-alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater and steam. The applicant stated that this item is not applicable because it does not use phosphate chemistry.

The staff reviewed the description of the applicant's Water Chemistry Program in LRA Section B.2.1.28 in order to verify which water chemistry is used for the plant's steam generators and confirmed that the applicant's plant does not use a Phosphate Chemistry Program. Therefore, the staff finds that this item is not applicable.

LRA Table 3.1.1, item 3.1.1-78 addresses the wall thinning due to flow-accelerated corrosion in steel steam generator tube support lattice bars exposed to secondary feedwater and steam. The applicant stated that this item is not applicable because the Seabrook steam generators do not contain tube support lattice bars.

The staff reviewed the steam generator description in LRA Section 2.3.1.4 and UFSAR Section 5.4 in order to verify the design of the plant's steam generators and confirmed that the applicant's steam generators (Westinghouse Model F steam generators) do not contain tube support lattice bars. Therefore, the staff finds that this item is not applicable.

LRA Table 3.1.1, item 3.1.1-79 addresses tube denting due to corrosion of steel tube support plates with Ni-alloy steam generator tubes exposed to secondary feedwater and steam. The applicant stated that this item is not applicable because the steam generator tube support plates are made of stainless steel.

The staff reviewed the steam generator description in LRA Section 2.3.1.4 and UFSAR Section 5.4 to verify the design of the plant's steam generators. Based on this review, the staff confirmed that the applicant's plant steam generators (Westinghouse Model F steam generators) have tube support plates made of ferritic stainless steel with quatrefoil tube holes and a design resistant to corrosion, which is expected to preclude denting. Therefore, the staff finds that this item is not applicable.

LRA Table 3.1.1, item 3.1.1-80 addresses the loss of fracture toughness due to thermal aging and neutron irradiation embrittlement of CASS RVI components. The applicant stated that these items are not applicable to Seabrook because the facility does not have CASS components in the RVIs.

The staff reviewed the reactor vessel internals description in LRA Section 2.3.1.3 and UFSAR Section 4.5 and 5.2 in order to verify the component material of the plant's reactor vessel internals and confirmed that the applicant's reactor vessel internals do not have CASS components. Therefore, the staff finds that this item is not applicable.

LRA Table 3.1.1, item 3.1.1-82 addresses crancking due to stress corrosion cracking in stainless steel steam generator primary side divider plate exposed to reactor coolant. The applicant stated that this item is not applicable because the Seabrook steam generators primary channel divider plate is not made of stainless steel.

The staff reviewed the steam generator description in LRA Section 2.3.1.4 and UFSAR Section 5.2 in order to verify the component material of the plant's steam generators and confirmed that the applicant's steam generators divider plate is not made of stainless steel but is made of SA-533 steel. Therefore, the staff finds that this item is not applicable.

LRA Table 3.1.1, item 3.1.1-87 addresses steel piping, piping components, and piping elements exposed to concrete and states that there are no aging effects, aging mechanisms, or AMPs. The GALL Report, Table IV, item IV.E-6 (RP-01) recommends that there is no aging effect or aging mechanism and that no AMP is recommended for this component group exposed to this environment, and, therefore, the staff finds the applicant's determination acceptable.

The staff reviewed the LRA and the UFSAR and concludes that the applicant does not have any AMR results that are applicable for these items.

3.1.2.1.2 Cracking Due to Stress-Corrosion Cracking and Primary Water Stress-Corrosion Cracking

LRA Table 3.1.1, item 3.1.1-69, addresses nickel-alloy reactor vessel primary inlet and outlet nozzle welds exposed to reactor coolant, which are being managed for cracking. The LRA credits the ASME Code Section XI ISI Subsections IWB, IWC, and IWD Program, the Water Chemistry Program, and the Nickel-Alloy Nozzles and Penetrations Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and GALL Report AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed. The associated AMR item cites generic note A for the ASME Code Section XI ISI Subsections IWB, IWC, and IWD Program and Water Chemistry Program. The associated AMR item cites generic note E for the Nickel-Alloy Nozzles and Penetrations Program.

For the item associated with generic note E, GALL Report AMPs XI.M1 and XI.M2 recommend using visual inspections, volumetric inspections, and water chemistry maintenance within the EPRI water chemistry guidelines to manage the aging of these items. In its review of components associated with item 3.1.1-69, for which the applicant cited generic note E, the staff noted that the ASME Code Section XI ISI Subsections IWB, IWC, and IWD Program, the Water Chemistry Program, and the Nickel-Alloy Nozzles and Penetrations Program all propose to manage the aging of nickel-alloy reactor vessel primary inlet and outlet nozzle welds through the use of visual inspections, volumetric inspections, repair and replacement activities, along with maintaining the water chemistry within the EPRI water chemistry guidelines.

The staff's evaluation of the applicant's ASME Code Section XI ISI Subsections IWB, IWC, and IWD Program, Water Chemistry Program, and Nickel-Alloy Nozzles and Penetrations Program are documented in SER Sections 3.0.3.1.1, 3.0.3.1.2, and 3.0.3.3.4, respectively. In its review of components associated with item 3.1.1-69, the staff finds the applicant's proposal to manage aging using the ASME Code Section XI ISI Subsections IWB, IWC, and IWD Program, Water Chemistry Program, and Nickel-Alloy Nozzles and Penetrations Program acceptable for the following reasons:

- The Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate the environmental effect on the aging and identifies the actions required if the parameters exceed the limits.

- The ASME Code Section XI ISI Subsection IWB, IWC, and IWD Program uses volumetric or visual inspection, which is adequate to detect and manage the aging effect consistent with the guidance in the GALL Report.
- The Nickel-Alloy Nozzles and Penetrations Program complies with the applicable NRC Orders and implements applicable NRC bulletins, generic letters, and staff-accepted industry guidelines.
- The use of these three programs is sufficient to manage the aging effects of the nickel-alloy reactor vessel primary inlet and outlet nozzle welds.

The staff concludes that the applicant 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 Conclusion for Aging Management Reviews Consistent with the GALL Report

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing the associated aging effects. On the basis of its review, the staff concludes that the AMR results that the applicant claimed to be consistent with the GALL Report are consistent with the GALL Report AMRs. Therefore, the staff concludes that the applicant demonstrated that the aging effects for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2 Aging Management Review 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 irradiation-assisted stress corrosion cracking (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 describes the applicant's AMR for managing cumulative fatigue damage in ASME Code Class 1 components and other non-Class 1 components that were analyzed to ASME Code Section III, Classes 1, fatigue evaluations. The applicant stated that fatigue is a TLAA as defined in 10 CFR 54.3, and these TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1). Further evaluation of these TLAAs is discussed separately in LRA Section 4.3.

The applicant identified that the following AMRs in LRA Table 3.1.1 are applicable and stated the following for each applicable item:

- Item 3.1.1-5—The applicant stated that the TLAAs for stainless steel and nickel-alloy RVIs components were evaluated in accordance with 10 CFR 54.21(c).
- Item 3.1.1-6—The applicant stated that the TLAAs for nickel-alloy tubes and sleeves in a reactor coolant and secondary feedwater and steam environment were evaluated in accordance with 10 CFR 54.21(c).
- Item 3.1.1-7—The applicant stated that steel and stainless steel RCPB closure bolting, head closure studs, support skirts and attachment welds, pressurizer relief tank components, steam generator components, piping, and components external surfaces and bolting were evaluated in accordance with 10 CFR 54.21(c).
- Item 3.1.1-8—The applicant stated that steel; stainless steel; and nickel-alloy RCPB piping, piping components, piping elements; flanges; nozzles and safe ends; pressurizer vessel shell heads and welds; heater sheaths and sleeves; penetrations; and thermal sleeves were evaluated in accordance with 10 CFR 54.21(c).
- Item 3.1.1-9—The applicant stated that steel; stainless steel; steel with nickel alloy or stainless steel cladding; nickel-alloy reactor vessel components such as flanges; nozzles; penetrations; pressure housings; safe ends; thermal sleeves; and vessel shells, heads and welds were evaluated in accordance with 10 CFR 54.21(c).
- Item 3.1.1-10—The applicant stated that steel; stainless steel; steel with nickel alloy or stainless steel cladding; nickel-alloy steam generator components such as flanges; penetrations; nozzles; safe ends, and vessel lower heads and welds were evaluated in accordance with 10 CFR 54.21(c).

The staff reviewed LRA Section 3.1.2.2.1 against the 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 these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c) and in accordance with SRP-LR Section 4.3, "Metal Fatigue Analysis." The staff reviewed the applicant's AMR items and finds that the AMR results are consistent with the recommendations of the GALL Report and SRP-LR except for the area identified below.

In its review of the components associated with item 3.1.1-8, the staff noted that LRA Tables 3.2.2-3, 3.2.2-4, and 3.3.2-3 included several AMR items that referenced item 3.1.1-8. The staff noted that LRA Section 4.3.7 indicated that these systems were designed in accordance with ASME Code Section III Class 2 and Class 3 requirements. By letter dated January 21, 2010, the staff issued RAI 3.3.2.2.1-2 asking the applicant to clarify which portions of these systems are represented by item 3.1.1-8 in LRA Tables 3.2.2-3, 3.3.2-4, and 3.3.2-3. The staff's review of the applicant's response to RAI 3.3.2.2.1-2 is documented in SER Sections 3.2.2.2.1 and 3.3.2.2.1.

Based on the staff's review, the staff concludes that the applicant met the SRP-LR Section 3.1.2.2.1 criteria. For those items that apply to LRA Section 3.1.2.2.1, the staff determined that the LRA is consistent with the GALL Report and that the applicant 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). SER Section 4.3 documents the staff's review of the applicant's evaluation of the TLAAs for these components.

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. LRA Section 3.1.2.2.2 addresses loss of material due to general, pitting, and crevice corrosion for certain portions (for PWRs) of the steam generators.

(1) Table 3.1.1, item 3.1.1-12, is only applicable to Babcock & Wilcox Co. OTSGs. Therefore, it is not applicable to Seabrook.

(2) Table 3.1.1, item 3.1.1-13, is applicable to BWRs only, as discussed in SER Section 3.1.2.1.1 above.

(3) Table 3.1.1, items 3.1.1-14 and 3.1.1-15, are applicable to BWRs only, as discussed in SER Section 3.1.2.1.1 above.

(4) LRA Section 3.1.2.2.2.4, is associated with LRA Table 3.1.1, item 3.1.1-16, and addresses steel steam generator components (feedwater and main steam nozzles, lower shell, secondary handholes, secondary manways, shell penetrations, top head, transition cone, and upper shell) exposed to secondary feedwater and steam, which are being managed for loss of material due to general, pitting, and crevice corrosion by the Water Chemistry Program and the ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program. The criteria in SRP-LR Section 3.1.2.2.2, item 4, states that loss of material due to general, pitting and crevice corrosion could occur for steel PWR steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam. The SRP-LR also states that the existing program relies on control of chemistry to mitigate corrosion and ISI to detect loss of material. The SRP-LR further states that, in accordance with NRC IN 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," the program may not be sufficient to detect pitting and crevice corrosion if general and pitting corrosion of the shell is known to exist, and augmented inspections may be needed to manage the aging effect. The SRP-LR clarifies that this special concern about capability of standard ASME Code Section XI inspections to detect pitting and crevice corrosion is limited to Westinghouse Model 44 and 51 steam generators, where a high stress region exists at the shell to transition cone weld.

The staff noted that the discussion in LRA Table 3.1.1, item 3.1.1-16, states that the steam generators are Westinghouse Model F and that additional inspection procedures (beyond those specified in ASME Code Section XI) are not required. The staff confirmed that the applicant's UFSAR Section 5.4.2.2 states that the steam generators are Model F and the NRC IN 90-04 recommendation regarding augmented inspections is limited to only Westinghouse steam generator Models 44 and 51. Because the applicant's steam generators are not Westinghouse Model 44 or 51, the staff finds acceptable the applicant's determination that augmented inspections are not needed.

The staff noted that in the GALL Report, AMR item IV.D1-12(R-34) is the only component related to SRP-LR Table 3.1.1, item 3.1.1-16. Specifically, AMR item IV.D1-12(R-34) is the steel steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam. However, the applicant extended the AMR results for this item to include other secondary steam generator components made of the same material and exposed to the same environment. The staff also noted that ASME Code Section XI, Examination Category C-A, item C1.10, is applicable for the steam generator upper and lower shell and transition cone and requires volumetric examination of shell circumferential welds at locations of gross structural discontinuity, specifically at the cylindrical shell to conical shell junctions. It was not clear to the staff if the applicant proposed this solely to rely on the code-required volumetric inspection, item C1.10, or whether it also intended to use visual examinations to confirm effectiveness of secondary water chemistry to mitigate loss of material due to general, pitting, and crevice corrosion for these components. By letter dated January 5, 2011, the staff issued RAI 3.1.2.2.2.4-01 asking the applicant to describe the examinations that will be used for this AMR item.

In its response dated February 3, 2011, the applicant stated that the Steam Generator Tube Integrity Program includes visual inspections for degradation of secondary handholds, secondary manways, shell penetrations, steam generator shell internal surface, transition cone internal surface, top head, and shell weld internal surfaces. The applicant further stated that the design of the steam generators prevents internal access to the feedwater and main steam nozzles for visual inspection and that, for these components, only volumetric examinations will be performed.

The applicant revised LRA Table 3.1.1, item 3.1.1-16, to state that both the ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program and the Steam Generator Tube Integrity Program will be used to verify the effectiveness of the Water Chemistry Program to manage loss of material due to general, pitting, and crevice corrosion in the steel components of the steam generators exposed to secondary feedwater or steam. In LRA Table 3.1.2-4, the applicant revised many AMR lines for steel components that refer to LRA Table 3.1.1, item 3.1.1-16. For three AMR lines applicable to the steel steam generator lower shell, transition cone, and upper shell, respectively, the AMP was revised to credit the Steam Generator Tube Integrity Program in addition to the ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program and the Water Chemistry Program for management of loss of material. For four AMR lines applicable to the steel steam generator secondary handholes, secondary manways, shell penetrations, and top head, respectively, the AMP was revised to credit the Steam Generator Tube Integrity Program and the Water Chemistry Program for management of loss of material. The staff noted that, for components where ASME Code Section XI specifies ISIs, the applicant is crediting the required ASME Code Section XI volumetric inspections and is supplementing those inspections with additional Steam Generator

Tube Integrity Program visual inspections. Additionally, for components where ASME Code Section XI does not specify inspections, the applicant is crediting Steam Generator Tube Integrity Program visual inspections for verification of Water Chemistry Program effectiveness.

The staff's evaluations of the applicant's ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program, Water Chemistry Program, and Steam Generator Tube Integrity Program are documented in SER Sections 3.0.3.1.1, 3.0.3.1.2, and 3.0.3.2.2, respectively. The staff noted that the applicant's Water Chemistry Program follows EPRI secondary water chemistry guidelines, which is consistent with recommendations in the GALL Report, and provides monitoring and control of secondary water chemistry to mitigate the potential for general, pitting, and crevice corrosion of steel secondary-side steam generator components. The staff also noted that the applicant's ASME Code Section XI ISI, Subsections IWB, IWC and IWD Program is consistent with recommendations in the GALL Report and provides the Code-required volumetric inspections and visual inspections of the steel secondary-side steam generator components. In addition, the staff noted that the applicant's Steam Generator Tube Integrity Program is based on NEI 97-02, Revision 2, "Steam Generator Program Guidelines," which is consistent with staff recommendations documented in the GALL Report. This program includes visual inspections that are capable of detecting loss of material due to general, pitting and crevice corrosion in steel secondary-side steam generator components.

The staff finds that the applicant met the further evaluation criteria, and the applicant's proposal to manage aging using the Water Chemistry Program, the ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program, and the Steam Generator Tube Integrity Program is acceptable for the following reasons:

- The Water Chemistry Program provides mitigation of the aging effect for steel secondary-side steam generator exposed to feedwater and steam.
- The ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program and the Steam Generator Tube Integrity Program provide examination of the components to confirm effectiveness of the Water Chemistry Program to mitigate the aging effects.
- The combination of programs proposed by the applicant is consistent with the recommendations in the GALL Report for aging management of these components.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.2, item 4, criteria. For those items that apply to LRA Section 3.1.2.2.2.4, the staff determined that the LRA is consistent with the GALL Report and that the applicant 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).

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

(1) LRA Section 3.1.2.2.3 is associated with LRA Table 3.1.1, item 3.1.1-17, and states that TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1) and that the evaluation of

this TLAA is addressed in Section 4.2. This is consistent with SRP-LR Section 3.1.2.2.3, item 1, and is, therefore, acceptable.

(2) LRA Section 3.1.2.2.3 is associated with LRA Table 3.1.1, item 3.1.1-18, and addresses steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds exposed to reactor coolant and neutron flux, which are being managed for loss of fracture toughness due to neutron irradiation embrittlement by Seabrook AMP B.2.1.19, "Reactor Vessel Surveillance." The criteria in SRP-LR Section 3.1.2.2.3, item 2, states that loss of fracture toughness due to neutron irradiation embrittlement could occur for steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds exposed to reactor coolant and neutron flux. The SRP-LR also states that the applicant should submit its proposed withdrawal schedule for approval prior to implementation. Untested capsules placed in storage must be maintained for future insertion. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the required information is included in the applicant's Reactor Vessel Surveillance Program.

The staff's evaluation of the applicant's Reactor Vessel Surveillance Program (LRA Section B.2.1.19) is documented in SER Section 3.0.3.2.11. The staff noted that the applicant did submit a Surveillance Program in 1983, and the LRA does include a commitment to follow the requirements of 10 CFR Part 50, Appendix H, and ASTM E185-82 protocol for the capsule withdrawal schedule (Commitment No. 20). In addition, the staff noted that Section B.2.1.19 includes a commitment (Commitment No. 21) to maintain untested capsules in storage for future insertion, if needed. The staff also noted that Table 3.1.1, item 3.1.1-18, is aligned with the applicant's commitments, as described in LRA Section B.2.1.19

Based on the acceptance of the Reactor Vessel Surveillance Program discussed in Section 3.0.3.2.11 and the commitments listed in LRA Appendix A, Section A.3, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.3, item 2, criteria. For those items that apply to LRA Section 3.1.2.2.3.2, the staff concludes that the LRA is consistent with the GALL Report and that the applicant 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).

3.1.2.2.4 Cracking Due to Stress-Corrosion Cracking and Intergranular Stress-Corrosion Cracking

Table 3.1.1, items 3.1.1-19 and 3.1.1-20 are not applicable to Seabrook, as they are applicable to BWRs only. See SER Section 3.1.2.1.1 above.

3.1.2.2.5 Crack Growth Due to Cyclic Loading

LRA Section 3.1.2.2.5 states that item 3.1.1-21 is not applicable because the stainless steel cladding is not fabricated with a high-heat-input welding process. SRP-LR Section 3.1.2.2.5 states that cyclic crack growth could occur if the cladding was welded to the RPV SA-508, Class 2 forgings using a high-heat-input welding process. After review, the staff concluded that item 3.1.1-21, crack growth due to cyclic loading, is not applicable because the cladding procedure used for the applicant's RV was qualified to ensure underclad cracking and the subsequent crack growth due to cyclic loading would not occur. The staff noted that the applicant used a special procedure qualification for its welding of the cladding to those RV components that were fabricated from SA-508, Class 2 low alloy steel forgings. The staff also noted that the procedure qualification included a special evaluation to assure freedom from underclad cracking in these cladding-to-forging welds. Specifically, the staff verified that UFSAR Sections 5.2.3 and 5.3.1.4 indicate that the applicant applied the NRC's recommended weld control process in Regulatory Guide (RG) 1.43, "Control of Stainless Steel Weld Cladding of Low Alloy Steel Components," as the process for controlling the welding fabrication of the cladding to those RV components that were fabricated from SA 508, Class 2 forging materials. The staff also verified that UFSAR Section 1.8 identifies that the applicant's procedural qualification was performed both in accordance with the weld fabrication requirements in Sections III and XI of the ASME Code and in accordance with supplemental qualification criteria (i.e., Position C.2) of RG 1.43, which provides the staff's recommended welding qualification process controls for avoiding underclad cracking in these cladding-to-forging welds. The staff determined that the RPV underclad cracking and the subsequent crack growth due to cyclic loading would not occur and, therefore, item 3.1.1-21 is not applicable. The staff evaluation of the absence of a TLAA for reactor vessel underclad cracking is documented in SER Section 4.7.1.2.

3.1.2.2.6 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement and Void Swelling

The staff reviewed LRA Section 3.1.2.2.6 and Table 3.1.1, Item 3.1.1-22, against the criteria in SRP-LR 3.1.2.2.6, which recommends no further AMR if the applicant provides a commitment in the UFSAR supplement to do the following:

- participate in the industry programs for investigating and managing aging effects on reactor internals
- evaluate and implement the results of the industry programs as applicable to the reactor internals
- upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval

The staff noted that the applicant's commitment (Commitment No. 1) in LRA Appendix A, Section A3, is consistent with the commitment described in SRP-LR 3.1.2.2.6.

The staff also noted that all of the AMR results lines that refer to Table 3.1.1, Item 3.1.1-22, align with the applicant's commitment as described in LRA Appendix A, Section A3. The staff finds the applicant's proposal acceptable because the discussion of the AMR item refers to the applicant's AMP (PWR Reactor Vessel Internals Program), which includes the appropriate commitment in the UFSAR supplement.

Based on the staff's evaluation, the staff concludes that the applicant's program meets the SRP-LR Section 3.1.2.2.6 criteria. For those AMR items that apply to LRA Section 3.1.2.2.6, the staff concludes 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).

3.1.2.2.7 Cracking Due to Stress-Corrosion Cracking

(1) LRA Section 3.1.2.2.7.1 is associated with LRA Table 3.1.1, item 3.1.1-23, and addresses stainless steel reactor vessel flange leak detection lines exposed to reactor coolant, which are being managed for cracking due to SCC by the ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program. SRP-LR Section 3.1.2.2.7, item 1, states that cracking due to SCC could occur for stainless steel exposed to reactor coolant. The SRP-LR also states that a plant-specific AMP should be evaluated to ensure that this aging effect is adequately managed. The applicant addressed the further evaluation criteria of the SRP-LR by stating that Seabrook will implement VT-2 examinations to identify and evaluate the degradation of stainless steel reactor vessel flange leak detection lines to ensure that there is no loss of intended function.

The staff's evaluation of the applicant's ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program is documented in SER Section 3.0.3.1.1. The staff noted that SCC will start at the surface and could be found with visual inspections as long as the critical flaw size is relatively large. The staff also noted that the stainless steel used for these components is extremely tough, such that the critical flaw size is normally large and easy to find with VT-2 inspections. In its review of components associated with item 3.1.1-23, the staff finds that the applicant met the further evaluation criteria; the applicant's proposal to manage aging using the ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program is acceptable because the proposed VT-2 inspections should find any cracking due to SCC.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.7, item 1, criteria. For those items that apply to LRA Section 3.1.2.2.7.1, the staff determined that the LRA is consistent with the GALL Report. The staff also finds that the applicant 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).

(2) LRA Section 3.1.2.2.7.2 is associated with LRA Table 3.1.1, item 3.1.1-24, and addresses Class 1 PWR CASS piping, piping components, and piping elements exposed to reactor coolant, which are being managed for cracking due to SCC by the Water Chemistry Program and the ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program. The criteria in SRP-LR Section 3.1.2.2.7 item 2, states that the cracking due to SCC could occur for Class 1 PWR CASS piping, piping components, and piping elements exposed to reactor coolant. SRP-LR Section 3.1.2.2.7 also states that the existing program relies on the control of water chemistry to mitigate SCC that could occur for CASS components that do not meet the NUREG–0313 guidelines with regard to ferrite and carbon contents. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program will be used to verify the effectiveness of the Water Chemistry Program.

In its review of components associated with LRA Table 3.1.1, item 3.1.1-24, the staff noted that the applicant related the AMR items to GALL Report, item IV.C2-3. The staff also noted that, for the CASS components that do not meet NUREG-0313 guidelines on material susceptibility, GALL AMR item IV.C2-3 recommends a plant-specific program to include adequate inspection methods and a flaw evaluation methodology for the CASS components that are susceptible to thermal aging embrittlement. LRA

Section 3.1.2.2.7.2 states that the ASME Code Section XI ISI, Subsections IWB, IWC and IWD Program rely on VT-2 examinations to identify and evaluate cracking of the CASS components. The staff noted that a VT-2 examination is used to detect leakage from pressure-retaining components, whereas a volumetric examination can detect a crack before there is leakage. The staff also noted that a surface examination or VT-1 examination can provide better resolution for detecting cracking than a VT-2 examination.

By letter dated January 5, 2011, the staff issued RAI 3.1.2.1-1 requesting that the applicant clarify whether a VT-2 examination is the only method used to detect this aging effect in CASS Class 1 piping, piping elements, and components. The staff also requested that, if another examination method such as volumetric, surface or VT-1 examination is used, the applicant should clarify what the examination method is and justify why the aging management method is adequate to detect and manage the aging effect. The staff further requested that, if the VT-2 examination is the only examination method used, the applicant should justify why a VT-2 examination without volumetric, surface, and VT-1 examinations is adequate to detect and manage cracking.

In its response dated February 3, 2011, the applicant stated that, as shown in LRA Table 3.1.1-23, the ASME Code Section XI ISI, Subsections IWB, IWC and IWD Program is credited to manage SCC of the Class 1 CASS piping, piping components, and piping elements. The applicant also stated that the VT-2 examination method was inadvertently identified as the only inspection method and that the ASME Code Section XI ISI, Subsections IWB, IWC and IWD Program is implemented in accordance with the requirements of 10 CFR 50.55a, with specified limitations, modifications, NRC approved alternatives, and applicable provisions of ASME Code Section XI. The applicant further indicated that it is revising LRA Section 3.1.2.2.7.2 accordingly to clarify that VT-2 examination is not the only examination credited to manage this aging effect. In addition, the applicant indicated that, during the period of extended operation, should the ISI Program require that volumetric examinations be performed per ASME Code Section XI, Table IWB-2500-1, Examination Category B-J, on the Class 1 pipe welds, then an ultrasonic examination method, qualified under ASME Code Section XI, Appendix VIII, will be used or an NRC-approved alternative (such as enhanced visual examination) will be implemented.

Based on its review, the staff finds the applicant's response to RAI 3.1.2.1-1 acceptable because the applicant clarified the following:

- The ASME Code Section XI ISI, Subsections IWB, IWC and IWD Program is implemented in accordance with the requirements of 10 CFR 50.55a, which is adequate to detect SCC of the components.
- A VT-2 examination is not the only inspection method used to manage this aging effect.
- If volumetric examinations are required per the ASME Code, an ultrasonic examination method qualified under ASME Code Section XI, Appendix VIII, will be used or an NRC-approved alternative (such as enhanced visual examination) will be implemented, which is adequate to detect cracking due to SCC of the components.

The staff's concerns described in RAI 3.1.2.1-1 are resolved.

The staff's evaluations of the applicant's Water Chemistry Program and ASME Code Section XI ISI, Subsections IWB, IWC and IWD Program are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.1, respectively. The applicant stated that the Water Chemistry Program controls water chemistry parameters by periodic monitoring and control of detrimental contaminants below the established limits that are known to cause material degradation. This program is based on EPRI guidelines, and periodic sampling is performed and analyzed for levels of chlorides, fluorides, sulfates, lithium, and dissolved oxygen and hydrogen so that cracking due to SCC in the CASS components is mitigated. The applicant further stated that the ASME Code Section XI ISI, Subsections IWB, IWC and IWD Program includes visual, surface, and volumetric inspections to detect and manage cracking due to SCC. The applicant stated that indications or relevant conditions are evaluated in accordance with IWB-3000 for Class 1 components. On the basis of its review, the staff finds that the applicant met the further evaluation criteria. Additionally, the applicant's proposal to manage aging using the Water Chemistry Program and ASME Code Section XI ISI, Subsections IWB, IWC and IWD Program is acceptable because the Water Chemistry Program monitors and controls water chemistry to mitigate cracking due to SCC, and the ASME Code Section XI ISI, Subsections IWB, IWC and IWD Program will perform inspections using visual, surface, and volumetric examinations in accordance with the requirements of the ASME Code Section XI, as modified and limited in 10 CFR 50.55a, which is adequate to verify the effectiveness of the Water Chemistry Program and manage cracking due to SCC.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.7 criteria. For those items that apply to LRA Section 3.1.2.2.7.2, the staff determined that the LRA is consistent with the GALL Report. The staff also finds that the applicant 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).

3.1.2.2.8 Cracking Due to Cyclic Loading

Table 3.1.1, items 3.1.1-25 and 3.1.1-26, are applicable to BWRs only, as discussed in SER Section 3.1.2.1.1 above.

3.1.2.2.9 Loss of Preload Due to Stress Relaxation

The staff reviewed LRA Section 3.1.2.2.9 against the criteria in SRP-LR Section 3.1.2.2.9. LRA Section 3.1.2.2.9 addresses loss of preload due to stress relaxation that could occur in stainless steel and Ni-alloy PWR RVIs screws, bolts, and hold down springs exposed to reactor coolant as an aging effect that the applicant will manage, consistent with the SRP-LR, by the ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program. This AMP is enhanced with Commitment No. 1, which is also identified in the UFSAR supplement description of the program.

The staff reviewed LRA Section 3.1.2.2.9 and Table 3.1.1, item 3.1.1-27, against criteria in SRP-LR 3.1.2.2.9. LRA Section 3.1.2.2.9 addresses loss of preload due to stress relaxation that could occur in stainless steel and Ni-alloy PWR RVIs screws, bolts, and hold down springs exposed to reactor coolant. The SRP-LR recommends no further AMR if the applicant provides a commitment in the UFSAR supplement to do the following:

- participate in the industry programs for investigating and managing aging effects on reactor internals
- evaluate and implement the results of the industry programs as applicable to the reactor internals
- upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval

The staff noted that the applicant's commitment (Commitment No. 1) in LRA Appendix A, Section A3, is consistent with the commitment described in SRP-LR 3.1.2.2.9.

The staff also noted that all of the AMR results lines that refer to Table 3.1.1, item 3.1.1-27, align with the applicant's commitment as described in LRA Appendix A, Section A3. The staff finds the applicant's proposal acceptable because the discussion of the AMR item refers to the applicant's AMP (PWR Vessel Internals Program), which includes the appropriate commitment in the UFSAR supplement.

Based on the staff's evaluation, the staff concludes that the applicant's program meets the SRP-LR Section 3.1.2.2.9 criteria. For those AMR items that apply to LRA Section 3.1.2.2.9, the staff concludes 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).

3.1.2.2.10 Loss of Material Due to Erosion

LRA Section 3.1.2.2.10, associated with LRA Table 3.1.1, item 3.1.1-28, addresses loss of material due to erosion in steel steam generator impingement plates and supports exposed to secondary feedwater. The applicant stated that this item is not applicable because steel steam generator feedwater impingement plates and supports do not exist in its steam generators. The staff reviewed UFSAR Section 5.4.2 and confirmed that the design of the applicant's steam generators do not contain steel steam generator feedwater impingement plates and supports; therefore, it finds the applicant's claim acceptable.

3.1.2.2.11 Cracking Due to Flow-Induced Vibration

Table 3.1.1, item 3.1.1-29, is applicable to BWRs only, as discussed in SER Section 3.1.2.1.1 above.

3.1.2.2.12 Cracking Due to Stress-Corrosion Cracking and Irradiation-Assisted Stress-Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.12 and Table 3.1.1, item 3.1.1-30, against criteria in SRP-LR 3.1.2.2.12. LRA Section 3.1.2.2.12 addresses cracking due to SCC and IASCC that may occur in stainless steel PWR reactor internals exposed to reactor coolant. This LRA section states that the existing program relies on control of water chemistry to mitigate cracking due to SCC and IASCC. SRP-LR 3.1.2.2.12 recommends no further AMR if the applicant provides a commitment in the UFSAR supplement to do the following:

- participate in the industry programs for investigating and managing aging effects on reactor internals

- evaluate and implement the results of the industry programs as applicable to the reactor internals
- upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval

The staff noted that the applicant's commitment (Commitment No. 1) in LRA Appendix A, Section A3, is consistent with the commitment described in SRP-LR 3.1.2.2.12.

The staff also noted that all of the AMR results lines that refer to Table 3.1.1, item 3.1.1-30, align with the applicant's commitment, as described in LRA Appendix A, Section A3. The staff finds the applicant's proposal acceptable because the discussion of the AMR item refers to the applicant's AMP (PWR Vessel Internals Program), which includes the appropriate commitment in the UFSAR supplement.

In LRA Section 3.1.2.2.12, the applicant stated that, for managing the aging of cracking due to SCC and IASCC of stainless steel reactor internals components exposed to reactor coolant, the facility's Water Chemistry Program is augmented by the commitment described above. When augmented by the commitment above, the staff finds the facility's Water Chemistry Program acceptable for managing SCC and IASCC of stainless steel reactor internals components exposed to reactor coolant because the Water Chemistry Program will control contaminants that can contribute to SCC of stainless steel.

The staff's evaluation of the applicant's Water Chemistry Program is documented in SER Section 3.0.3.1.2. In its review of components associated with item 3.1.1-30, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program acceptable because use of the Water Chemistry Program to manage cracking is consistent with GALL when combined with the commitment described above.

Based on the programs identified, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.12 criteria. For those items that apply to LRA Section 3.1.2.2.12, the staff determined that the LRA is consistent with the GALL Report. The staff also finds that the applicant 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).

3.1.2.2.13 Cracking Due to Primary Water Stress-Corrosion Cracking

LRA Section 3.1.2.2.13 and LRA Table 3.1.1, item 3.1.1-31, address 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, with the exception of reactor vessel upper head nozzles and penetrations exposed to reactor coolant. These components are being managed for cracking due to PWSCC by the ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program, the Nickel-Alloy Nozzles and Penetrations Program, and the Water Chemistry Program. SRP-LR Section 3.1.2.2.13 states that cracking due to PWSCC could occur for PWR components made of nickel alloy and steel with nickel-alloy cladding exposed to reactor coolant. The SRP-LR also states that, with the exception of reactor vessel upper head nozzles and penetrations, the GALL Report recommends ASME Code Section XI ISI (for Class 1 components) and control of water chemistry. For nickel-alloy components, no further AMR is necessary if the applicant complies with applicable NRC Orders and provides a commitment in the UFSAR supplement to implement applicable bulletins, generic letters, and staff-accepted industry guidelines. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will implement those programs mentioned above to manage the aging effects of cracking due to PWSCC in nickel-alloy components in the RCS, in the nickel-alloy bottom instrument tube and core support pads/core guide lugs in the reactor vessel, and the nickel-alloy steam generator primary nozzle weld in the steam generator.

The staff's evaluations of the applicant's three AMPs, ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program, Water Chemistry Program, and Nickel-Alloy Nozzles and Penetrations Program, are documented in SER sections 3.0.3.1.1, 3.0.3.3.4, and 3.0.3.1.2, respectively. In its review of these AMPs, the staff found them to be acceptable for managing aging. Additionally, the staff noted that the Nickel-Alloy Nozzles and Penetrations Program states that the applicant will comply with applicable NRC Orders. Additionally, Commitment No. 59, which is associated with the Nickel-Alloy Nozzles and Penetration Program (submitted by letter dated January 13, 2011, and contained in LRA Section A.2.2.3), commits to implementing bulletins, generic letters, and staff-accepted industry guidelines.

In its review of components associated with Table 3.1.1, item 3.1.1-31, the staff finds the applicant's proposal to manage aging using the ASME Code Section XI ISI Program, the Water Chemistry Program, and the Nickel-Alloy Nozzles and Penetrations Program, acceptable. The components under consideration are consistent with those in the GALL Report, and the AMPs proposed by the applicant are consistent with the GALL Report and contain the commitment recommended in SRP-LR Section 3.1.2.2.13.

Based on its review, the staff concludes that the AMP proposed by the applicant for those items which are currently under consideration meets the criteria contained in SRP-LR Section 3.1.2.2.13. Additionally, the staff concludes 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).

3.1.2.2.14 Wall Thinning Due to Flow-Accelerated Corrosion

LRA Section 3.1.2.2.14 is associated with LRA Table 3.1.1, item 3.1.1-32, and addresses the steel steam generator feedwater inlet ring and supports exposed to secondary feedwater and steam, which are being managed for wall thinning due to flow-accelerated corrosion by the Steam Generator Tube Integrity Program. The criteria in SRP-LR Section 3.1.2.2.14 states that wall thinning due to flow-accelerated corrosion could occur for steel feedwater inlet rings and supports. The SRP-LR and the GALL Report also state that NRC IN 91-19, "Steam Generator Feedwater Distribution Piping Damage," cites evidence of flow-accelerated corrosion in steam generators and recommends that a plant-specific AMP be evaluated because existing programs may not be capable of mitigating or detecting wall thinning due to flow-accelerated corrosion. The applicant addressed the further evaluation criteria of the SRP-LR by stating that IN 91-19 addresses wall thinning due to flow-accelerated corrosion in Combustion Engineering-designed steam generator feedwater inlet rings and supports, and it is not directly applicable to Seabrook, which uses Westinghouse Model F steam generators. The applicant further stated that it will manage wall thinning due to flow-accelerated corrosion in the steel steam generator feedwater inlet rings and supports by using the Steam Generator Tube Integrity Program. The Steam Generator Tube Integrity Program implements many industry guidelines and incorporates a balance of prevention, inspection, evaluation, repair, and leakage monitoring measures to assure that existing environmental conditions are not causing wall thinning that could result in a loss of component intended function.

The staff's evaluation of the applicant's Steam Generator Tube Integrity Program is documented in SER Section 3.0.3.2.2. In its review of components associated with item 3.1.1-32 and the Steam Generator Tube Integrity Program described in LRA Section B.2.1.10, the staff noted that the applicant stated that the program includes management of wall thinning from flow-accelerated corrosion of steam generator components. However, the applicant does not describe the inspections or analytical techniques used to ensure that excessive wall thinning due to flow-accelerated corrosion does not occur in the components.

By letter dated January 5, 2011, the staff issued RAI 3.1.2.2.14-01 asking the applicant to describe its examination techniques and the evaluation methodology used to manage wall thinning in the steam generator feedwater inlet rings and supports.

In its response dated February 3, 2011, the applicant stated that the Steam Generator Tube Integrity Program uses visual inspections of the steam generators' secondary-side internals, including the steam generator feedwater inlet ring and supports, and does not include predictive analytical methodology for wall thinning due to flow-accelerated corrosion. The applicant further stated that it performs a degradation assessment of the steam generators during each RFO, and visual inspections are required for the degradation assessment. The applicant stated that the visual inspections identify the general condition of the steam generator components and allow the search for evidence of erosion-corrosion, irregular geometry, and structural changes, and the acceptance criteria require that there be no visible signs of degradation. The applicant stated that its steam generator degradation assessment for the feedwater rings typically includes outside surface, supports, welds, cross-over pipe, feedwater nozzle knuckle region, feedwater ring to J-nozzle intersection on the outside diameter, J-nozzle to feedwater ring joint on the inside diameter, feedwater ring weld backing rings, and all welds. The degradation assessment ensures that degradation of components is identified, and corrective actions are taken before loss of component-intended functions.

The staff finds the applicant's response to RAI 3.1.2.2.14-01 acceptable because the applicant met the further evaluation criteria, and the applicant's proposal to manage aging using the Steam Generator Tube Integrity Program is acceptable for the following reasons:

- The applicant's Steam Generator Tube Integrity Program includes visual inspections of the steel steam generator feedwater inlet rings and supports performed at each RFO.
- The visual inspections of the feedwater inlet rings and supports are capable of identifying loss of material and wall thinning that may occur in these components caused by flow-accelerated corrosion.
- Results of the visual inspections are used as input to a degradation assessment of steam generator components performed during each RFO so that corrective action, if needed, can be implemented before loss of component-intended function occurs.

The staff's concern described in RAI 3.1.2.2.14-01 is resolved.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.14 criteria. For those items that apply to LRA Section 3.1.2.2.14, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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).

3.1.2.2.15 Changes in Dimensions Due to Void Swelling

The staff reviewed LRA Section 3.1.2.2.15 and Table 3.1.1, item 3.1.1-33, against criteria in SRP-LR 3.1.2.2.15. LRA Section 3.1.2.2.15 addresses changes in dimensions due to void swelling that could occur in stainless steel and Ni-alloy PWR RVI components exposed to reactor coolant. The SRP-LR recommends no further AMR if the applicant provides a commitment in the UFSAR supplement to do the following:

- participate in the industry programs for investigating and managing aging effects on reactor internals
- evaluate and implement the results of the industry programs as applicable to the reactor internals
- upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval

The staff noted that the applicant's commitment (Commitment No. 1) in LRA Appendix A, Section A3, is consistent with the commitment described in SRP-LR 3.1.2.2.15. The staff also noted that all of the AMR results lines that refer to Table 3.1.1, item 3.1.1.33, are aligned with the applicant's commitment, as described in LRA Appendix A, Section A3. The staff finds the applicant's proposal acceptable because the discussion of the AMR item refers to the applicant's AMP (PWR Vessel Internals Program), which includes the appropriate commitment in the UFSAR supplement.

Based on its review, the staff concludes that the applicant 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).

3.1.2.2.16 Cracking Due to Stress-Corrosion Cracking and Primary Water Stress-Corrosion Cracking

(1) LRA Section 3.1.2.2.16.1 is associated with LRA Table 3.1.1, items 3.1.1-34 and 3.1.1-35. It addresses stainless steel canopy seal pressure housing and nickel-alloy CRD pressure housing exposed to reactor coolant that are being managed for cracking due to SCC and PWSCC by the ASME Code Section XI ISI, Subsection IWB, IWC, and IWD Program and the Water Chemistry Program. The criteria in SRP-LR Section 3.1.2.2.16, item 1, state that cracking due to SCC and PWSCC could occur for steel steam generator components and steam generator tube-to-tube sheet welds made or clad with nickel alloy exposed to reactor coolant. The SRP-LR also states that the GALL Report recommends ASME Code Section XI ISI and control of water chemistry to manage this aging effect. Additionally, no further AMR of PWSCC of nickel alloys is needed if the applicant complies with applicable NRC Orders and provides a commitment in the UFSAR supplement to implement applicable bulletins, generic letters, and staff-accepted industry guidelines. In its review, the staff noted that the nickel-alloy CRD pressure housing is not a reactor vessel head penetration or nozzle for which the further evaluation criterion associated with the NRC Orders and UFSAR supplement is applicable. In addition, the staff noted that GALL Report, Revision 2, item IV.A2.RP-55 recommends the ASME Code Section XI ISI, Subsection IWB, IWC, and IWD Program and Water Chemistry Program to manage cracking due to SCC and PWSCC of stainless steel and nickel-alloy CRD pressure housings.

By letter dated November 15, 2010, the applicant submitted Supplement 2 to the LRA. As described in this document, LRA Section 3.1.2.2.16.1 addresses the further evaluation criteria of the SRP-LR by stating that the GALL Report, Revision 1, recommends a commitment in the UFSAR supplement to implement applicable bulletins and letters and staff-accepted industry guidelines, which is met by crediting its Nickel-Alloy Nozzles and Penetrations Program to manage PWSCC of the nickel-alloy nozzles and penetrations. The applicant also clarified that the commitment recommended by the SRP-LR is associated with the Nickel-Alloy Nozzles and Penetrations Program. However, the Nickel-Alloy Nozzles and Penetrations Program is not applicable to the nickel-alloy CRD pressure housing because the component is not a penetration or nozzle. The applicant further stated that cracking due to SCC and PWSCC of the CRD pressure housings is being managed by the ASME Code Section XI ISI, Subsection IWB, IWC, and IWD Program and Water Chemistry Program. The staff finds the applicant's claim acceptable because the applicant's use of the ASME Code Section XI ISI, Subsection IWB, IWC, and IWD Program and Water Chemistry Program is sufficient to manage SCC of the nickel-alloy CRD pressure housing, as evaluated below.

The staff's evaluations of the applicant's ASME Code Section XI ISI, Subsection IWB, IWC, and IWD Program and Water Chemistry Program are documented in SER Sections 3.0.3.1.1 and 3.0.3.1.2, respectively. In its review of components associated with item 3.1.1-34, the staff finds that the applicant met the further evaluation criteria and the applicant's proposal to manage aging using the ASME Code Section XI ISI, Subsection IWB, IWC, and IWD Program and Water Chemistry Program is acceptable for the following reasons:

- The Water Chemistry Program establishes the plant water chemistry control parameters, and their limits to mitigate an environment that is conducive for cracking and takes corrective actions if the parameters exceed these limits.
- The ASME Code Section XI ISI, Subsection IWB, IWC, and IWD Program is adequate to detect and manage cracking of these components, consistent with the GALL Report.
- The use of the Water Chemistry Program in conjunction with the ASME Code Section XI ISI, Subsection IWB, IWC, and IWD Program is sufficient to manage cracking due to SCC of the components through periodic inspections and water chemistry control.

LRA Section 3.1.2.2.16, item 1, also states that LRA Table 3.1.1, item 3.1.1-35, is not applicable because the plant does not have OTSGs and, therefore, does not have the components associated with these steam generators.

By letter dated December 14, 2010, the staff also issued RAI B.2.1.10-1 to request additional information regarding the applicant's steam generator tube-to-tubesheet welds, The applicant provided a response by letter dated January 13, 2011, to clarify the dispositioning of its tube-to-tubesheet welds with respect to its RCPB and to also explain how it will manage cracking due to SCC and PWSCC of the steam generator tube sheets and tube-to-tubesheet welds made of steel with nickel-alloy cladding. The staff's evaluation of the applicant's response to RAI B.2.1.10-1 is documented in SER Section 3.0.3.2.2, and Open Item OI 3.0.3.2.2-1 was identified for the applicant provide additional information regarding aging management of the welds. Resolution for OI 3.0.3.2.2-1 will be documented in Section 3.0.3.2.2.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.16, item 1, criteria. For those items that apply to LRA Section 3.1.2.2.16.1, the staff determined that the LRA is consistent with the GALL Report and that the applicant 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 3.1.2.2.16.2 is associated with LRA Table 3.1.1, item 3.1.1-36, and addresses nickel alloy and stainless steel pressurizer spray heads exposed to reactor coolant that are being managed for cracking due to SCC for stainless steel components and PWSCC for nickel-alloy components by the Water Chemistry and One-Time Inspection Programs. SRP-LR Section 3.1.2.2.16, item 2, states that cracking due to SCC could occur on stainless steel pressurizer spray heads, and cracking due to PWSCC could occur on nickel-alloy pressurizer spray heads. The SRP-LR also states that the existing program relies on control of water chemistry to mitigate this aging effect. The GALL Report recommends one-time inspection to confirm that cracking does not occur. Furthermore, for nickel-alloy welded spray heads, the GALL Report recommends no further AMR if the applicant complies with applicable NRC Orders and provides a commitment in the UFSAR supplement to implement applicable bulletins, generic letters, and staff-accepted industry guidelines. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will implement the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage cracking due to SCC in the stainless steel pressurizer spray head exposed to reactor coolant.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. In these evaluations, the staff found these programs to be acceptable means to manage aging.

In its review of components associated with LRA Table 3.1.1, item 3.1.1-36, the staff noted that all of the associated components were constructed from stainless steel, i.e., there are no nickel-alloy components included in this AMR item. The staff, therefore, finds that the applicant met the further evaluation criteria. The applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection Programs is acceptable for the following reasons:

- The applicant's proposed programs are consistent with those recommended by LRA Section 3.1.2.2.16, item 2, for stainless steel components.
- The Water Chemistry and One-Time Inspection Programs were evaluated by the staff and found to be acceptable to manage aging.
- There are no nickel-alloy components included in this AMR item, making the provisions of LRA Section 3.1.2.2.16, item 2, which apply to nickel-alloy components, not applicable.

Based on its review, the staff concludes that the aging management proposed by the applicant for those items which are currently under consideration meets the criteria contained in item 2 of SRP-LR Section 3.1.2.2.16. The staff concludes 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).

3.1.2.2.17 Cracking Due to Stress-Corrosion Cracking, Primary Water Stress-Corrosion Cracking, and Irradiated-Assisted Stress-Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.17 and Table 3.1.1, item 3.1.1-37, against the criteria in SRP-LR 3.1.2.2.17, which addresses cracking due to SCC, PWSCC, and IASCC that could occur in stainless steel and Ni-alloy PWR reactor internal components exposed to reactor coolant. LRA Section 3.1.2.2.17 noted that the existing program relies on control of water chemistry to mitigate cracking due to SCC, PWSCC, and IASCC of these PWR reactor internals components exposed to reactor coolant. SRP-LR 3.1.2.2.17 recommends no further AMR if the applicant provides a commitment in the UFSAR supplement to do the following:

- participate in the industry programs for investigating and managing aging effects on reactor internals
- evaluate and implement the results of the industry programs as applicable to the reactor internals
- upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval

The staff noted that the applicant's commitment (Commitment No. 1) in LRA Appendix A, Section A3, is consistent with the commitment described in SRP-LR 3.1.2.2.17. The staff also noted that all of the AMR results lines that refer to Table 3.1.1, item 3.1.1-37, align with the applicant's commitment as described in LRA Appendix A, Section A3. The staff finds the applicant's proposal acceptable because the discussion of the AMR item refers to the applicant's AMP (PWR Vessel Internals Program), which includes the appropriate commitment in the UFSAR supplement.

In LRA Section 3.1.2.2.17, the applicant stated that, for managing the aging of cracking due to SCC, PWSCC, and IASCC of stainless steel and nickel-alloy reactor internals components exposed to reactor coolant, the applicant's Water Chemistry Program is augmented by the commitment described above. When augmented by the commitment above, the staff finds the applicant's Water Chemistry Program acceptable for managing SCC and IASCC of stainless steel reactor internals components exposed to reactor coolant because the Water Chemistry Program will control contaminants that can contribute to SCC of stainless steel.

The staff's evaluation of the applicant's Water Chemistry Program is documented in SER Section 3.0.3.1.2. In its review of components associated with item 3.1.1-37, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program acceptable because use of the Water Chemistry Program to manage cracking is consistent with the GALL Report when combined with the commitment described above.

Based on the programs identified, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.17 criteria. For those items that apply to LRA Section 3.1.2.2.17, the staff determined that the LRA is consistent with the GALL Report and that the applicant 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).

3.1.2.2.18 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–J, that the combination of component type, material, environment, and AERM does not correspond to an 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 item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR 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 item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the 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 if the applicant demonstrated that the aging effects will be adequately managed so that the intended functions 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 Coolant System, Summary of Aging Management Evaluation, LRA Table 3.1.2-1

In LRA Tables 3.1.2-1, 3.1.2-2, 3.1.2-3, and 3.1.2-4, the applicant stated that for Ni-alloy components exposed to air with borated water leakage, there is no aging effect, and no AMP is proposed. The AMR items cite generic note G and plant-specific note 1. Plant-specific note 1 states the following:

> NUREG-1801 does not include air with borated water leakage for nickel-alloy components. Similar to V.F-13 for stainless steel, there are no aging effects for nickel alloy in air with borated water leakage. Additionally, the American Welding Society (AWS) "Welding Handbook," (Seventh Edition, Volume 4, 1982, Library of Congress) identifies that nickel chromium alloy materials that are alloyed with iron, molybdenum, tungsten, cobalt or copper in various combinations have improved corrosion resistance.

The staff reviewed the associated items in the LRA and confirmed that the applicant's use of generic note G for these items is appropriate in that the GALL Report, Revision 1, does not include entries for nickel alloys exposed to air with borated water leakage. The staff noted that the GALL Report, Revision 2, dated December 2010, includes entries for nickel alloys exposed to air with borated water leakage. These entries indicate that no AERM is present for this material-environment combination. The staff also noted these items in the GALL Report, Revision 2, are based in part on EPRI Report 1000975, “Boric Acid Corrosion Guidebook, Revision 1.” This report contains data (pages 4–43) showing that “[t]here was no measurable corrosion of stainless steel piping surfaces or Inconel weld metal joining the stainless steel and carbon steel piping sections.” The staff, therefore, concurs with the applicant’s assessment that aging management is not necessary for nickel-alloy components exposed to air with borated water leakage, as described above.

In LRA Table 3.1.2-1, the applicant stated that the AERM for CASS RCS piping and fittings exposed to reactor coolant (internal) greater than 482 °F (250 °C), which is susceptible to loss of fracture toughness due to thermal aging embrittlement, is not applicable, and no AMP is proposed. The AMR item cites generic note I. The applicant addressed the CASS piping and fitting components in LRA Table 3.1.2-1 for the RCS and related these components to LRA item 3.1.1-57. The applicant also stated that these components have molybdenum and ferrite contents below the threshold for susceptibility to thermal aging embrittlement.

The staff reviewed the associated items in the LRA and confirmed that loss of fracture toughness due to thermal aging embrittlement is not applicable to the component, material and environment combination. LRA Table 3.1.1, item 3.1.1-57, indicates that the molybdenum and ferrite contents for this component are below the threshold (less than 0.5 percent molybdenum and less than 20 percent ferrite), such that the components are not susceptible to this aging effect, consistent with GALL Report AMP XI.M12.

The staff also noted that UFSAR Table 5.2-2 indicates that the piping in the RCS is made of SA-376, Grade 304N, or centrifugally-cast SA-351, Grade CF8A. The staff noted that SA-376, Grade 304N, material is not a CASS material and, therefore, finds that this material is not susceptible to thermal aging embrittlement, consistent with the GALL Report. The staff also finds that centrifugally-cast SA-351, Grade CF8A, is a low-molybdenum CASS material, which is not susceptible to thermal aging embrittlement, consistent with the GALL Report AMP XI.M12. In a teleconference held on March 3, 2011, the applicant further clarified that the reactor coolant piping, described in UFSAR Table 5.2-2, is made of SA-376, Grade 304N, material, and the listed centrifugal casting material has not been used for the reactor coolant piping.

In LRA Table 3.1.2-1, the applicant stated that the stainless steel bolting exposed to air-indoor is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because, even though stainless steel bolting exposed to air-indoor is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, Table IX.C of the GALL Report states that stainless steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion and cracking due to SCC. The staff noted that the environment of interest, air-indoor, would not induce SCC or loss of material in stainless steel material because stainless steel is inherently resistant to corrosion in the air-indoor environment. Therefore, the aging effect of concern is loss of preload, which is addressed in the AMR.

The staff’s evaluation of the applicant’s Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for stainless steel bolting exposed to air-indoor in the

RCS, the GALL Report has items for other material bolting exposed to air-indoor managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload. It also inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.1.2.3.2 Reactor Vessel, Summary of Aging Management Evaluation, LRA Table 3.1.2-2

The staff's evaluation for Ni-alloy components exposed to borated water leakage that are not subject to an aging effect requiring management, with generic note G, is documented in SER Section 3.1.2.3.1.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.1.2.3.3 Reactor Vessel Internals, Summary of Aging Management Evaluation, LRA Table 3.1.2-3

Table 3.1.2-3, "Reactor Vessel Internals, Summary of Aging Management Evaluation," item 366, addresses Ni-Alloy flux thimble tubes exposed to air with borated water leakage (internal) and assigns Note G to this component. The staff's evaluation for Ni-alloy components exposed to borated water leakage that are not subject to an aging effect requiring management, with generic note G, is documented in SER Section 3.1.2.3.1.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.1.2.3.4 Steam Generator, Summary of Aging Management Evaluation, LRA Table 3.1.2-4

In LRA Table 3.1.2-4, the applicant stated that the nickel-alloy steam generator tubes exposed to reactor coolant are being managed for reduction of heat transfer by the Water Chemistry Program. The AMR item cites generic note H. The AMR items also cite plant-specific note 4, which states that reduction of heat transfer due to fouling is not in the GALL Report for this component, material, and environment but that reduction of heat transfer is applicable to this combination and, therefore, will be managed by the Water Chemistry Program.

The staff reviewed the associated items in the LRA. However, it was not clear to the staff how the Water Chemistry Program alone would ensure that reduction of heat transfer is appropriately managed. Typically, for reduction of heat transfer, both a Water Chemistry Program and an Inspection Program are used to manage this aging effect. By letter date January 5, 2011, the staff issued RAI 3.1.2.4-1, requesting that the applicant justify how the Water Chemistry Program alone is sufficient to determine that steam generator tubes are not affected by reduction of heat transfer when exposed to reactor coolant.

In its response dated February 3, 2011, the applicant stated that reduction of heat transfer due to fouling was inadvertently added as an AMR item and that neither plant-specific nor any industry operating experience has indicated that this aging effect is applicable to steam generator tubes exposed to reactor coolant. The applicant has removed the AMR item from the LRA. The staff finds the applicant's response acceptable because reduction of heat transfer due to fouling for tubes internally exposed to reactor coolant is not an aging affect that has been observed in steam generators, which is consistent with the GALL Report. The staff's concern described in RAI 3.1.2.4-1 is resolved.

In LRA Table 3.1.2-4, the applicant stated that the nickel-alloy steam generator tubes exposed to secondary feedwater or steam are being managed for reduction of heat transfer by the Water Chemistry Program and Steam Generator Tube Integrity Program. The AMR item cites generic note H. The AMR items also cite plant-specific note 3, which states that reduction of heat transfer due to fouling is not in the GALL Report for this component, material, and environment, but that reduction of heat transfer is applicable to this combination and, therefore, will be managed by the Water Chemistry Program and Steam Generator Tube Integrity Program.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because steam generator tubes are likely places where fouling can occur due to buildup of corrosion products, and evidence of fouling has been shown to occur in certain locations in the steam generators (ASM International, *Environments and Industries*, pp. 362–385, 2006).

The staff's evaluations of the applicant's Water Chemistry Program and Steam Generator Tube Integrity Program are documented in SER Sections 3.0.3.1.2 and 3.0.3.2.2, respectively. The staff noted that the Water Chemistry Program relies upon periodic monitoring and control of detrimental contaminants in the water to manage reduction of heat transfer. The staff also noted that the Steam Generator Tube Integrity Program uses visual inspections to evaluate sludge buildup and other corrosion phenomena. The staff finds the applicant's proposal to manage aging using the Water Chemistry Program and Steam Generator Tube Integrity Program acceptable because the maintenance of water chemistry will prevent buildup of products that can lead to reduction of heat transfer, and the visual inspections will be able to identify the occurrence of fouling that could lead to a reduction of heat transfer.

The staff's evaluation for Ni-alloy components exposed to borated water leakage that are not subject to an aging effect requiring management, with generic note G, is documented in SER Section 3.1.2.3.1.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.1.3 Conclusion

The staff concludes that the applicant provided sufficient information to demonstrate that the effects of aging for the reactor vessel, RVIs, RCS, and steam generator 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 ESFs systems components and component groups of the following systems:

- combustible gas control system
- containment building spray system
- RHR system
- safety injection system

3.2.1 Summary of Technical Information in the Application

LRA Section 3.2 provides AMR results for the engineered safety features (ESF) systems' components. LRA Table 3.2.1, "Summary of Aging Management Evaluation for Engineered Safety Features," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the 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 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.

3.2.2 Staff Evaluation

The staff reviewed LRA Section 3.2 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the ESF systems' 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 conducted an onsite audit of 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 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 audit evaluation are documented in SER Section 3.2.2.1.

In the onsite audit, the staff also selected 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 3.2.2.2 acceptance criteria. The staff's audit evaluations are documented in SER Section 3.2.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed were appropriate for the material-environment combinations specified. The staff's evaluations are documented in SER Section 3.2.2.3.

For SSCs which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR 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 systems 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 ECCS (3.2.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Consistent with GALL Report (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 Seabrook (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	Water Chemistry and One-Time Inspection	Consistent with GALL Report (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 Seabrook (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 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	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.2.3)
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 Seabrook (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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Not applicable to Seabrook (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 Seabrook (see SER Section 3.2.2.2.4)

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 in 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	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.2.5)
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	Consistent with GALL Report (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 PWRs (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	Not applicable	Not applicable to PWRs (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	Water Chemistry and One-Time Inspection	Not applicable to Seabrook (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)

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 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 (MIC)	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	No Yes	Not applicable	Not applicable to Seabrook (see SER Section 3.2.2.2.9)
Stainless steel piping, piping components, and piping elements exposed to treated water > 140 °F (> 60 °C) (3.2.1-18)	Cracking due to SCC and IGSCC	BWR SCC and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.1.1)
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	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.1.1)
CASS piping, piping components, and piping elements exposed to treated water (borated or unborated) > 482 °F (> 250 °C) (3.2.1-20)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Not applicable	Not applicable to PWRs (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 Seabrook (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 Seabrook (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

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 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	Consistent with GALL Report
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water > 140 °F (>60 °C) (3.2.1-25)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System	Consistent with GALL Report
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	Closed-Cycle Cooling Water System	Consistent with GALL Report
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	Closed-Cycle Cooling Water System	Consistent with GALL Report
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	Closed-Cycle Cooling Water System	Consistent with GALL Report
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	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
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	Closed-Cycle Cooling Water System	Consistent with GALL Report
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
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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report
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 Seabrook (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	Not applicable	Not applicable to Seabrook (see SER Section 3.2.2.1.1)
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	Fire Water System	Consistent with GALL Report (see SER Section 3.2.2.1.2)

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
Steel heat exchanger components exposed to raw water (3.2.1-36)	Loss of material due to general, pitting, crevice, galvanic, and MIC, and fouling	Open-Cycle Cooling Water System	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Not applicable to Seabrook (see SER Section 3.2.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to raw water (3.2.1-37)	Loss of material due to pitting, crevice, and MIC	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to Seabrook (see SER Section 3.2.2.1.1)
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 MIC, and fouling	Open-Cycle Cooling Water System	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	Consistent with GALL Report (see SER Section 3.2.2.1.3)
Stainless steel heat exchanger components exposed to raw water (3.2.1-39)	Loss of material due to pitting, crevice, and MIC, and fouling	Open-Cycle Cooling Water System	No	Fire Water System Program	Consistent with GALL Report (see SER Section 3.2.2.1.3)
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 Seabrook (see SER Section 3.2.2.1.1)
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	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
Gray cast iron piping, piping components, and 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 Seabrook (see SER Section 3.2.2.1.1)
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 Seabrook (see SER Section 3.2.2.1.1)
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	Not applicable	Not applicable to Seabrook (see SER Section 3.2.2.1.1)
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	Boric Acid Corrosion	Consistent with GALL Report
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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report
CASS piping, piping components, and piping elements exposed to treated borated water > 482 °F (>250 °C) (3.2.1-47)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Not applicable	Not applicable to Seabrook (see SER Section 3.2.2.1.1)

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 or stainless-steel-clad steel piping, piping components, piping elements, and tanks (including safety injection tanks/accumulators) exposed to treated borated water > 140 °F (> 60 °C) (3.2.1-48)	Cracking due to SCC	Water Chemistry	No	Water Chemistry and One-Time Inspection	Consistent with GALL Report
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	Water Chemistry and One-Time Inspection	Consistent with GALL Report
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	None	Consistent with GALL Report
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
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

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) (3.2.1-54)	None	None	No	Not applicable	Not applicable to Seabrook (see SER Section 3.2.2.1.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (3.2.1-55)	None	None	No	Not applicable	Not applicable to Seabrook (see SER Section 3.2.2.1.1)
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	None	Consistent with GALL Report

The staff's review of the ESF systems' component groups followed several approaches. One approach, documented in SER Section 3.2.2.1, 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 3.2.2.2, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report for which further evaluation is recommended. A third approach, documented in SER Section 3.2.2.3, 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 ESF system components is documented in SER Section 3.0.3.

3.2.2.1 Aging Management Review Results Consistent with the GALL Report

LRA Section 3.2.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the ESF systems' components:

- ASME Code Section XI ISI Subsections IWB, IWC, and IWD Program
- Bolting Integrity Program
- Boric Acid Corrosion Program

- Closed-Cycle Cooling Water System Program
- External Surfaces Monitoring Program
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program
- Lubricating Oil Analysis Program
- One-Time Inspection Program
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program
- Water Chemistry Program

LRA Tables 3.2.2-1 through 3.2.2-4 summarize AMRs for the ESF 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 claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine if 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 item describing how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with Notes A–E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR 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 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 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 items to verify consistency with the GALL Report and to ensure 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 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 items to verify consistency with the GALL Report. The staff also determined whether the AMR 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 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 items to verify consistency with the GALL Report. The staff confirmed whether the AMR item of the different component was applicable to the component under review and whether the exceptions to the GALL Report AMPs was 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 item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff reviewed these 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 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.

LRA Table 3.2.1, item 3.2.1-48, addresses stainless steel or stainless steel clad steel piping, piping components, piping elements, and tanks exposed to treated borated water greater than 140 °F (60 °C), which are being managed for cracking due to SCC. The LRA credits the Water Chemistry Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry" to ensure that these aging effects are adequately managed. The associated AMR items cite generic note A.

In its review of components associated with item 3.2.1-48, for which the applicant cited generic note A, the staff noted that it was unclear if any of these components is a Class 1 valve. The staff noted that GALL Report item IV.C2-3 recommends both Water Chemistry Program and a plant-specific program to manage cracking of CASS Class 1 piping, piping components, and piping elements, which have carbon content greater than 0.035 percent or ferrite content less than 7.5 percent, based on the material susceptibility criteria described in NUREG-0313, Revision 2. The staff also noted that the recommendations of GALL Report item IV.C2-3 may be applicable for the CASS valve bodies exposed to treated borated water greater than 140 °F (60 °C) in LRA Tables 3.1.2-1, 3.2.2-3, and 3.3.2-3.

By letter dated January 5, 2011, the staff issued RAI 3.1.2.1-01 requesting that the applicant clarify whether any of the CASS valves in the RCS, RHR system, or chemical and volume control system is a Class 1 component, for which the GALL Report recommends a plant-specific program, in addition to the Water Chemistry Program, to manage SCC. The staff also requested the applicant to justify why the Water Chemistry Program alone, without a plant-specific program, is adequate to manage the cracking due to SCC for the CASS Class 1 component if any of these CASS valves is a Class 1 component that has carbon content greater than 0.035 percent or ferrite content less than 7.5 percent.

In its response dated February 3, 2011, the applicant stated that the valves associated with the items for CASS valve bodies in the environment of treated borated water greater than 140 °F (60 °C) are not Class 1 components. The applicant further stated that no plant-specific program is required in addition to the Water Chemistry Program to manage cracking due to SCC based on the material susceptibility criteria described in NUREG-0313, Revision 2. The staff finds the applicant's response acceptable because the applicant clarified that none of the CASS valve bodies are Class 1 components and that the applicant's management of cracking using the Water Chemistry Program is consistent with the GALL Report. The staff finds the applicant's response unacceptable because the guidance in the SRP-LR and GALL Report was revised in License Renewal Interim Staff Guidance (LR-ISG), LR-ISG-2011-01, "Aging Management of

Stainless Steel Structures and Components in Treated Borated Water," to add the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage stainless steel components for loss of material, cracking, and reduction of heat transfer in treated borated water environments that are not controlled to low oxygen levels. The staff noted that, prior to issuance of LR-ISG-2011-01; the SRP-LR and GALL Report guidance inappropriately credited the boron in borated water as a corrosion inhibitor in place of other aging management activities.

By letter dated May 29, 2012, the staff issued RAI 3.2.1.48-1 requesting that the applicant describe how the effectiveness of the Water Chemistry Program to manage cracking will be verified for stainless steel components exposed to treated borated water with greater than 5 ppb oxygen. Pending the staff's review of the applicant's response, this issue is identified as Open Item OI 3.2.2.1-1.

LRA Table 3.2.1, item 3.2.1-49 addresses stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated borated water which are being managed for loss of material due to pitting and crevice corrosion. The LRA credits the Water Chemistry Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed. The associated AMR items cite generic notes A or C.

In its review of components associated with item number 3.2.1-49 for which the applicant cited generic notes A or C, the staff noted that the guidance in the SRP-LR and GALL Report was revised in LR-ISG-2011-01, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water," to add the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage stainless steel components for loss of material, cracking, and reduction of heat transfer in treated borated water environments that are not controlled to low oxygen levels. The staff noted that, prior to the issuance of LR-ISG-2011-01, the SRP-LR and GALL Report guidance inappropriately credited the boron in borated water as a corrosion inhibitor in place of other aging management activities.

By letter dated May 29, 2012, the staff issued RAI 3.2.1.48-1 requesting that the applicant describe how the effectiveness of the Water Chemistry Program to manage loss of material will be verified for stainless steel components exposed to treated borated water with greater than 5 ppb oxygen. Pending the staff's review of the applicant's response, this issue is identified as Open Item OI 3.2.2.1-1.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, pending resolution of Open Item OI 3.2.2.1-1, 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, pending resolution of Open Item OI 3.2.2.1-1, that the applicant 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).

3.2.2.1.1 Aging Management Review Results Identified as Not Applicable

LRA Table 3.2.1, items 3.2.1-18, 3.1.2-19, and 3.2.1-20, state that these items are applicable only to BWRs. The staff confirmed that these items do not apply because the unit is a PWR design. Based on this determination, the staff finds that the applicant provided an acceptable basis for concluding AMR items 3.2.1-18, 3.1.2-19, and 3.2.1-20 are not applicable.

For LRA Table 3.2.1, items 3.2.1-21, 3.2.1-22, 3.2.1-33, 3.2.1-34, 3.2.1-36, 3.2.1-37, 3.2.1-40, 3.2.1-42, 3.2.1-43, 3.2.1-44, and 3.2.1-47 the applicant claimed these items were not applicable. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results that are applicable for these items.

LRA Table 3.2.1, item 3.2.1-54 addresses steel piping, piping components, and piping elements exposed to controlled indoor air (external) and states that there are no aging effects, aging mechanisms, or AMPs. The GALL Report, Table V, item V.F-16 (EP-4) recommends that there is no aging effect or aging mechanism and that no AMP is recommended for this component group exposed to this environment, and, therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.2.1, item 3.2.1-55 addresses steel and stainless steel piping, piping components, and piping elements exposed to concrete and states that there are no aging effects, aging mechanisms, or AMPs. The GALL Report, Table V, items V.F-14 (EP-20) and V.F-17 (EP-5) recommend that there is no aging effect or aging mechanism and that no AMP is recommended for these component groups exposed to this environment, and, therefore, the staff finds the applicant's determination acceptable.

3.2.2.1.2 Loss of Material Due To General, Pitting, Crevice, and Microbiologically-Influenced Corrosion, and Fouling

LRA Table 3.2.1, item 3.2.1-35, addresses steel containment isolation piping and components internal surfaces exposed to raw water, which are being managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion, and fouling. The applicant credits the Fire Water System Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E with plant-specific notes that state the raw water environment is associated with the Fire Water System; therefore, the Open-Cycle Cooling Water System Program is not applicable.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, GALL Report AMP XI.M20 recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.2.1, item 3.2.1-35, for which the applicant cited generic note E, the staff noted that the Fire Water System Program proposes to manage the aging of steel isolation piping and components internal surfaces through the use of inspections, periodic flushing, system performance testing, and chemical additions to prevent microbiological growth.

The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.2.8. In its review of components associated with LRA Table 3.2.1, item 3.2.1-35, the staff finds the applicant's proposal to manage aging using the Fire Water System Program acceptable because the program conducts inspections roughly every outage and uses preventive actions including chemical additions and performance verification.

The staff concludes that the applicant 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, which are being managed for loss of material due to pitting, crevice, and microbiologically-influenced corrosion, and fouling. The applicant credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E with plant-specific noted that state the raw water environment is associated with radioactive liquid waste drainage; therefore, the Open-Cycle Cooling Water System Program is not applicable.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, GALL Report AMP XI.M20 recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.2.1, item 3.2.1-38, 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 the aging of stainless steel isolation piping and components' internal surfaces through the use of periodic inspection on the internal surfaces of components. It was not clear to the staff how the opportunistic visual inspections will be able to manage aging of components in a raw water system that does not include chemical treatments or surveillances. By letter dated January 5, 2011, the staff issued RAI 3.3.2.2-1 requesting that the applicant justify the use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component Program, which is only a visual inspection program to manage aging in the raw water environment.

In its response dated February 3, 2011, the applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was chosen because the internal raw water environments are not covered by any other AMP. The applicant also stated that its conclusion to use this AMP is supported by information in Revision 2 to the GALL Report, that this program applies to components exposed to any water systems not included in the open-cycle cooling water, closed treated water, or fire water AMPs. The applicant further stated that its equipment inspections have been successful at identifying and resolving corrosion or degradation before it affects the ability of the component to perform its intended function. The staff finds the applicant's response acceptable because the GALL Report, Revision 2, allows for components exposed to raw water, which are not part of the open-cycle cooling water, to be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component Program; therefore, the applicant's proposal is in accordance with the current staff position. The staff's concern described in RAI 3.3.2.2-1 is resolved.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. In its review of components associated with LRA Table 3.2.1, item 3.2.1-38, the staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable. The program conducts inspections during periodic system surveillances or maintenance activities when internal surfaces are accessible and monitors parameters such as corrosion, corrosion byproducts, coating degradation, scale/deposits, pits, and surface discoloration and discontinuities, which is sufficient to manage aging of these components and is consistent with the staff's current position.

The staff concludes that the applicant 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 3.2.1-39, 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 applicant credits the Fire Water System Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E with plant-specific notes that state the raw water environment is associated with the fire protection system; therefore, the Open-Cycle Cooling Water System Program is not applicable.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, GALL Report AMP XI.M20 recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.2.1, item 3.2.1-39, for which the applicant cited generic note E, the staff noted that the Fire Water System Program proposes to manage the aging of stainless steel heat exchanger components through the use of inspections, periodic flushing, system performance testing, and chemical additions to prevent microbiological growth.

The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.2.8. In its review of components associated with LRA Table 3.2.1, item 3.2.1-39, the staff finds the applicant's proposal to manage aging using the Fire Water System Program acceptable because the program conducts inspections roughly every outage and uses preventive actions including chemical additions and performance verification.

The staff concludes that the applicant 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 Aging Management Review Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.2.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the ESF system components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to cladding breach
- 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 MIC
- 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 audited and reviewed the applicant's evaluation to determine if 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 3.2.2.2. 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, which is associated with LRA Table 3.2.1, item 3.2.1-1, addresses steel and stainless steel piping, piping components, and piping elements in RHR and safety injection (SI) systems exposed to treated water and being managed for cumulative fatigue damage. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3, and is required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that its evaluation of this TLAA is addressed separately in LRA Section 4.3.

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 cumulative fatigue damage of steel and stainless steel piping, piping components, and piping elements in the ESF systems is a TLAA, and these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements of 10 CFR 54.21(c) and in accordance with SRP-LR Section 4.3, "Metal Fatigue Analysis." The staff reviewed the applicant's AMR items and finds that the AMR results are consistent with the recommendations of the GALL Report and SRP-LR for managing cumulative fatigue damage in steel and stainless steel piping, piping components, and piping elements exposed to treated water, except as identified below.

The staff noted that LRA Tables 3.2.2-3 and 3.2.2-4 do not include any applicable items for management of cumulative fatigue damage in the RHR and SI systems. By letter dated January 21, 2010, the staff issued RAI 3.3.2.2.1-1, Request 1, asking the applicant to include, in LRA Table 3.2.2-3 for RHR system and Table 3.2.2-4 for SI system, any applicable items related to the management of cumulative fatigue damage in non-Class 1 components or provide the basis for excluding these items from the LRA.

In its response dated February 18, 2011, the applicant amended LRA Tables 3.2.2-3 and 3.2.2-4 to include the associated AMR items for the RHR and SI systems, consistent with GALL AMR item V.D1-27. The applicant stated that six rows representing TLAAs of stainless steel pressure boundary components such as orifice, piping and fittings, pump casing, thermowell, and valve body exposed to treated borated water have been added to LRA Table 3.2.2-3, and five rows have been added to LRA Table 3.2.2-4.

Based on its review of the amended LRA Tables 3.2.2-3 and 3.2.2-4, the staff finds the applicant's response to RAI 3.3.2.2.1-1, Request 1, and the additions of the AMR items acceptable because they are consistent with GALL AMR item V.D1-27 for the RHR and SI systems. The staff's concern described in RAI 3.3.2.2.1-1, Request 1, is resolved.

In its review of LRA Tables 3.2.2-3 and 3.2.2-4, the staff also noted AMR items associated with item 3.1.1-8 regarding TLAAs of piping and fittings (Class 1, including less than 4 in.), valve body, and orifice (Class 1). The staff noted that LRA Section 4.3.7 states that the RHR and SI system components were designed in accordance with ASME Code Section III, Class 2 and Class 3, requirements. It is not clear to the staff which piping and piping components are represented in these rows in LRA Tables 3.2.2-3 and 3.2.2-4 and if these components represent the portions of the RHR and SI systems that are located inside the reactor containment.

By letter dated January 21, 2010, the staff issued RAI 3.3.2.2.1-2 asking the applicant to clarify which portions of the RHR and SI systems are represented by item 3.1.1-8 in LRA Tables 3.2.2-3 and 3.3.2-4. The staff also requested that the applicant clarify the inconsistency between LRA Section 4.3.7, which states that the RHR and SI systems components were designed to ASME Code Section III Class 2 and Class 3 requirements and LRA Table 3.1.1, item 3.1.1-8, which represents Class 1 components. Furthermore, the staff requested that the applicant identify the TLAA in LRA Section 4 that represents these AMR items. As part of the RAI 3.3.2.2.1-2, the staff also sent similar questions regarding the chemical and volume control system (CVCS). The staff's evaluation of the applicant's response to the portion of the RAI related to the CVCS is documented in SER Section 3.3.2.2.1.

In its response dated February 18, 2011, the applicant clarified that item 3.1.1-8 represents the Class 1 RCPB components in the RHR (LRA Table 3.2.2-3) and SI (Table 3.2.2-4) systems. The applicant also stated that AMR items that represents the Class 2 and Class 3 components in the RHR and SI systems were added to LRA Table 3.2.2-3 and Tables 3.2.2-4, as part of the response in RAI 3.3.2.2.1-1. The applicant stated that the Class 1 RCPB components in the RHR and SI systems, which are part of the NSSS, are evaluated in LRA Section 4.3.1 and 4.3.2. The applicant also stated that the TLAAs for Class 2 and Class 3 components are evaluated in LRA Section 4.3.7.

Based on its review, the staff finds the applicant's response to RAI 3.3.2.2.1-2 acceptable because the applicant clarified the AMR items and associated TLAAs for Class 1 RCPB components and Class 2 and Class 3 components in the RHR and SI systems. The applicant's AMR results are consistent with the recommendations of the GALL Report. The staff's review of the applicant's TLAAs associated with the Classes 1, 2, and 3 components are documented in SER Section 4.3. The staff's concern described in RAI 3.3.2.2.1-2 is resolved.

Based on the staff's review, it concludes that the applicant met the SRP-LR Section 3.2.2.2.1 criteria. For those items that apply to LRA Section 3.2.2.2.1, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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). SER Section 4.3 documents the staff's review of the applicant's evaluation of the TLAA for these components.

3.2.2.2.2 Loss of Material Due to Cladding Breach

LRA Section 3.2.2.2.2, associated with LRA Table 3.2.1, item 3.2.1-2, addresses loss of material due to cladding breach in pump casings of steel with stainless steel cladding exposed to treated borated water. The applicant stated that this item is not applicable because the plant's ESF systems do not contain pump casings comprised of steel with stainless steel cladding. The staff reviewed LRA Sections 2.3.2 and 3.2 and the UFSAR and confirmed that no in-scope pump casings of steel with stainless steel cladding exposed to treated borated water are present in the ESF systems; therefore, it finds the applicant's claim acceptable.

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 following 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, piping components, and piping 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 criteria in SRP-LR Section 3.2.2.2.3, item 1, state that loss of material due to pitting and crevice corrosion could occur for internal surfaces of stainless steel containment isolation piping, piping components, and piping elements exposed to treated water. The SRP-LR also states that the Water Chemistry Program relies on monitoring and control of water chemistry to mitigate degradation, and a one-time inspection of select components at susceptible locations is an acceptable method to determine if an aging effect does not occur or progresses very slowly such that the component's intended function will be maintained during the period of extended operation. The applicant addressed the further evaluation criteria of the SRP-LR by stating that loss of material due to pitting and crevice corrosion of stainless steel piping components exposed to treated water will be managed by the Water Chemistry and One-Time Inspection Programs.

The applicant stated that for item 3.2.1-3, the applicability is limited to stainless steel containment building spray and demineralized water system components exposed to treated water. The staff noted that a search of LRA Section 3.2 and the applicant's UFSAR confirmed that no in-scope piping, piping components, and piping elements exposed to treated water are present in the containment isolation systems, except for those listed in LRA Section 3.2.2.2.3, item 1 and item 3.2.1-3.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. In its review of components associated with item 3.2.1-3, the staff finds that the applicant met the further evaluation criteria. The staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection Program acceptable because the Water Chemistry Program uses chemical sampling and corrective actions to ensure that impurities are minimized to reduce aging due to loss of material. Additionally, the One-Time Inspection Program will perform visual, surface, volumetric, or other non-destructive examination methods of components determined to be most susceptible to degradation to verify the effectiveness of the Water Chemistry Program for managing the aging effects of loss of material.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.3, item 1, criteria. For those items that apply to LRA Section 3.2.2.2.3.1, the staff determined that the LRA is consistent with the GALL Report. The staff also finds that the applicant 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 3.2.2.2.3.2, associated with LRA Table 3.2.1, item 3.2.1-4, addresses loss of material from pitting and crevice corrosion in stainless steel piping, piping components, and piping elements exposed to a soil environment. The applicant stated that this item is not applicable because there are no stainless steel components in the ESF systems that are exposed to soil. The staff reviewed LRA Sections 2.3.2 and 3.2 and the applicant's UFSAR and confirmed that no in-scope stainless steel piping, piping components and piping elements exposed to a soil environment are present in the ESF systems; therefore, it finds the applicant's claim acceptable.

(3) LRA Section 3.2.2.2.3, item 3, associated with LRA Table 3.2.1, item 3.2.1-5, addresses loss of material due to pitting and crevice corrosion in BWR stainless steel and aluminum piping, piping components, and piping elements exposed to treated water. The applicant stated that this item is not applicable because it is only applicable to BWRs. The staff reviewed the SRP-LR and LRA Section 3.2 and noted that this item is associated only with BWRs; therefore, it finds the applicant's claim acceptable.

(4) LRA Section 3.2.2.2.3.4, referenced by LRA Table 3.2.1, item 3.2.1-6, addresses stainless steel and copper-alloy piping, piping components, and piping elements exposed to lubricating oil, 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 criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material through examination of susceptible locations in stainless steel piping components in the RHR and SI systems, copper-alloy piping components and copper-alloy heat exchanger components in the SI system, and stainless steel heat exchanger components in the SI system. In addition, the applicant stated that MIC will be managed on the stainless steel piping components exposed to lubricating oil in the RHR and SI systems as well as stainless steel heat exchanger components exposed to lubricating oil in the SI system.

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 loss of material from pitting and crevice corrosion could occur for stainless steel and 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. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil control should be confirmed to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation to verify the effectiveness of the Lubricating Oil Program for which a one-time inspection of selected 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's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. In its review of components associated with item 3.2.1-6, that staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report. Additionally, the applicant stated that the One-Time Inspection Program will be used to examine stainless steel piping and copper-alloy piping components to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.2.2.2.3, item 4; therefore, the applicant's AMR is consistent with the GALL Report.

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 the items that apply to LRA Section 3.2.2.2.3.4, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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, associated with LRA Table 3.2.1, item 3.2.1-7, addresses loss of material from pitting and crevice corrosion in partially encased stainless steel tanks exposed to raw water due to cracking of the perimeter seal from weathering. The applicant stated that this item is not applicable because there are no partially encased stainless steel tanks in the ESF systems exposed to raw water. The staff reviewed LRA Sections 2.3.2 and 3.2 and the applicant's UFSAR and confirmed that no in-scope partially encased stainless steel tanks exposed to raw water are present in the ESF systems; therefore, it finds the applicant's claim acceptable.

(6) LRA Section 3.2.2.2.3.6, associated with LRA Table 3.2.1, item 3.2.1-8, addresses loss of material due to pitting and crevice corrosion in stainless steel piping, piping components, piping elements, and tanks exposed to condensation (internal). The applicant stated that this item is not applicable because its ESF systems do not contain stainless steel piping, piping components, piping elements, and tanks exposed to condensation (internal). The staff reviewed LRA Sections 2.3.2 and 3.2 and the UFSAR and confirmed that no in-scope stainless steel piping, piping components, piping elements, and tanks exposed to condensation (internal) are present in the ESF systems; therefore, it finds the applicant's claim acceptable.

3.2.2.2.4 Reduction of Heat Transfer Due to Fouling

The staff reviewed LRA Section 3.2.2.2.4 against the following criteria in SRP-LR Section 3.2.2.2.4:

(1) LRA Section 3.2.2.2.4.1, is associated with LRA Table 3.2.1, item 3.2.1-9, and addresses steel, stainless steel, and copper heat exchanger tubes exposed to lubricating oil, which are being managed for reduction of heat transfer due to fouling by the Lubricating Oil Analysis and One-Time Inspection Programs.

The criteria in SRP-LR Section 3.2.2.2.4, item 1, state that reduction of heat transfer due to fouling may occur in steel, stainless steel, and copper-alloy heat exchanger tubes exposed to lubricating oil. The SRP-LR also states that the existing AMP controls lube oil chemistry to mitigate this aging effect, and the effectiveness should be confirmed because the lube oil chemistry controls may not be effective in precluding fouling. The SRP-LR further states that a one-time inspection of selected components at susceptible locations is an acceptable method to verify the program's effectiveness. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will implement the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of heat transfer due to fouling in the chemical and volume control, diesel generator, and SI systems.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. In its review of components associated with item 3.2.1-9, the staff finds that the applicant has met the further review criteria, and the applicant's proposal to manage aging using the specified AMPs acceptable because the Lubricating Oil Analysis Program includes periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits. Additionally, the One-Time Inspection Program will verify the effectiveness of the Lubricating Oil Analysis Program to manage this aging effect.

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 items that apply to LRA Section 3.2.2.2.4.1, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 3.2.2.2.4.2, is associated with LRA Table 3.2.1, item 3.2.1-10, and addresses stainless steel heat exchanger tubes exposed to treated water. The applicant stated that this item is not applicable because there are no stainless steel heat exchanger tubes exposed to treated water in the ESF systems. To verify this, the staff reviewed LRA Section 3.2 and noted that, although there were no in-scope stainless steel heat exchanger tubes exposed to treated water in the ESF systems, there were several systems with heat exchanger tubes exposed to treated borated water. Since the related item, EP-34, from SRP-LR Table 3.2.1, was derived from a previous SER for heat exchanger tubes exposed to treated borated water, the applicant's determination that this item was not applicable did not appear appropriate. By letter dated February 24, 2011, the staff issued RAI 3.2.2.2.4.2-1 requesting that the applicant provide additional bases regarding the non-applicability of this item and address how the reduction in heat transfer would be managed for heat exchanger tubes identified as having a heat transfer function.

In its response dated March 22, 2011, the applicant stated that the "treated borated water" environment is different than the "treated water" environment. The applicant provided the definitions of treated water and treated boated water from the GALL Report Section IX.D, which states that, unlike the PWR reactor coolant environment (treated borated water), the BWR reactor coolant environment (treated water) does not contain boron, a recognized corrosion inhibitor. The applicant also referred to GALL Report Section IX.F, which describes fouling as an accumulation of deposits that may be due to biofouling or particulate fouling, such as sediment, silt, or corrosion products. The applicant further stated that none of the heat exchanger tubes in LRA Section 3.2 are exposed to treated water; however, the containment building spray and RHR heat exchanger tubes have an internal environment of treated borated water and an external environment of closed-cycle cooling water. The applicant also stated that reduction of heat transfer was applied to the tube side exposed to the closed-cycle cooling water but not to the tube side exposed to treated borated water, and it provided the following basis:

- The Seabrook Station's determination that reduction of heat transfer is not an aging effect in treated borated water environment is based on plant and industry operating experience. Seabrook Station is not aware of any fouling in treated borated water environment leading to reduction of heat transfer in stainless steel heat exchanger tubes. This conclusion is consistent with NUREG-1801 Rev.1. NUREG-1801 Rev 1 does not identify reduction of heat transfer as an aging effect for stainless steel heat exchanger tubes in treated borated water environment.

- Fouling of the stainless steel heat exchanger tubes on the treated borated water side would only occur through the buildup of corrosion products. Since the Seabrook Station's treated borated water contains boron, a corrosion inhibitor, corrosion product buildup resulting in reduction of heat transfer in treated borated water environment is not a credible aging effect/mechanism. This is further validated by NUREG-1801, Rev 1 line items V.A-27, and V.D1-30 (NUREG-1800, Table 3.2-1, items 48 and 49), which state that Water Chemistry Program alone (for PWR primary water) is adequate for managing loss of material in stainless steel components exposed to treated borated water indicating that corrosion is not expected to occur in stainless steel components exposed to treated borated water. In the absence of corrosion, corrosion product buildup will not occur. Additionally, since reduction of heat transfer in treated borated water is not identified as a potential aging effect, no line items for reduction of heat transfer in treated borated water appear in the LRA.
- Seabrook's conclusion is consistent with NUREG-1810 Rev 1 and Rev 2, as well as the NRC staff conclusions as stated in Beaver Valley Final SER (Section 3.2.2.3.2) and Prairie Island SER (Section 3.2.2.2.4).

The staff reviewed the applicant's response and the cited portions of the GALL Report. The staff noted that, although the GALL Report, Revision 1, states that boron is a recognized corrosion inhibitor, the GALL Report, Revision 2, deleted that discussion from the definition of treated water. The staff also reviewed AMR items V.A-27 and V.D1-30 (SRP-LR, Table 3.2-1 item 49) and noted that the GALL Report credits Water Chemistry to manage loss of material due to pitting and crevice corrosion in stainless components exposed to treated borated water. The staff also noted that, although the basis for adding these items in the GALL Report, Revision 1, stated that a significant loss of material was not expected, the potential for corrosion and consequently corrosion product buildup still exists. The staff also reviewed the Beaver Valley and Prairie Island SERs and the associated LRAs cited by the applicant and noted that both LRAs identified reduction of heat transfer for stainless steel heat exchanger tubes in a treated borated water environment as an aging effect requiring managing. Based on the above, by letter dated May 23, 2011, the staff issued RAI 3.2.2.2.4.2-1A, requesting the applicant to provide its justification to demonstrate that heat exchanger tubes which have a heat transfer intended function do not need to include a reduction of heat transfer aging effect requiring management. In addition, the RAI requested the applicant to provide the plant-specific and industry operating experience cited in its previous response demonstrating that reduction in heat transfer was not a credible aging effect for the components in question.

In its response dated June 2, 2011, the applicant revised LRA Tables 3.2.2-2 and 3.2.2-3 to include AMR items for stainless steel heat exchanger components exposed to treated borated water that are being managed for reduction of heat transfer by the Water Chemistry Program. The AMR items cite generic note H and plant-specific note 4, which states that reduction of heat transfer due to fouling is not in the GALL Report for this component, material and environment combination. The staff finds the applicant's response unacceptable because the guidance in the SRP-LR and GALL Report was revised in LR-ISG-2011-01, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water," to add the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage stainless steel components for loss of material, cracking, and reduction of heat transfer in treated borated water environments that are not controlled to low oxygen levels. The staff noted that, prior to the issuance of LR-ISG-2011-01, the SRP-LR and GALL Report guidance inappropriately credited the boron in borated water as a corrosion inhibitor in place of other aging management activities.

By letter dated May 29, 2012, the staff issued RAI 3.2.1.48-1 requesting that the applicant describe how the effectiveness of the Water Chemistry Program to manage reduction of heat transfer will be verified for stainless steel components exposed to treated borated water with greater than 5 ppb oxygen. Pending the staff's review of the applicant's response, this issue is identified as Open Item OI 3.2.2.1-1.

3.2.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

LRA Section 3.2.2.2.5 is associated with LRA Table 3.2.1, item 3.2.1-11, and addresses hardening and loss of strength due to elastomer degradation. The applicant states that this aging effect is not applicable to Seabrook because this item is applicable to BWRs only. SRP-LR Section 3.2.2.2.5 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 uncontrolled indoor air. The staff finds that SRP-LR Section 3.2.2.2.5 is not applicable because Seabrook is a PWR, and the staff guidance in this SRP-LR section is only applicable to BWRs.

3.2.2.2.6 Loss of Material Due to Erosion

LRA Section 3.2.2.2.6 is associated with LRA Table 3.2.1, item 3.2.1-12, and addresses the stainless steel high pressure pump minimum flow orifices in the CVCS exposed to treated borated water, which the applicant proposed to manage for loss of material due to erosion with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The criterion in SRP-LR Section 3.2.2.2.6 states that loss of material due to erosion could occur in high-pressure safety injection (HPSI) pump minimum flow orifices exposed to treated borated water. The SRP-LR also states that a plant-specific AMP should be evaluated for erosion of the orifice due to extended use of the centrifugal HPSI pump for normal charging. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is adequate to manage the aging effect in these components.

In its review of components associated with LRA Table 3.2.1, item 3.2.1-12, the staff noted that the only components associated with this item are the minimum flow orifices downstream of the two centrifugal charging and high-head injection pumps in the CVCS. The staff also noted that the applicant proposed to manage the aging effect for these components through the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff further noted that this program consists of inspections of opportunity, performed during pre-planned periodic system and component surveillances or during maintenance activities, when the systems are opened and the surfaces are made accessible for visual inspection. Based on the CVCS piping configuration and the limited number of charging pump minimum flow orifices, it was not clear to the staff if opportunities for inspection of these components occur routinely, in accordance with scheduled preventive maintenance or periodic surveillance, or if opportunities for inspection are normally available only during corrective maintenance after degradation or failure of the component may have occurred.

By letter dated January 5, 2011, the staff issued RAI 3.2.2.2.6-01 requesting the applicant to explain whether opportunities for inspection of the charging pump bypass orifices are routinely available. The staff also asked the applicant to justify how the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will be capable of detecting degradation in these components before failure of their intended function if routine opportunities for inspection are not available.

In its response dated February 3, 2011, the applicant stated that the CVCS high-pressure pump minimum flow orifices are welded in place and are not routinely available for internal visual inspection. The applicant further stated that the minimum flow orifices have multiple internal plates with multiple orifice holes and that these design features of the minimum flow orifices make volumetric examination for dimensional comparison impractical. The applicant proposed to manage loss of material due to erosion in minimum flow orifices with the Water Chemistry Program. The applicant also stated that its TSs require quarterly inservice testing of the CVCS high-pressure pumps and that this testing can provide early indication of orifice degradation. The applicant revised LRA Table 3.3.2-3, LRA Section 3.2.2.2.6, and LRA Table 3.2.1, item 3.2.1-12, to state that the Water Chemistry Program, rather than the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, will be used to manage loss of material due to erosion in CVCS stainless steel orifices exposed to treated borated water.

The staff's evaluation of the applicant's Water Chemistry Program is documented in SER Section 3.0.3.1.2. The staff noted that the applicant's Water Chemistry Program is consistent with GALL Report AMP XI.M2, "Water Chemistry." The staff also noted that the GALL Report credits the Water Chemistry Program with providing management for loss of material due to corrosion in stainless steel components exposed to a treated borated water environment; however, the GALL Report does not credit the Water Chemistry Program with managing loss of material due to erosion. The staff further noted that the applicant had neither proposed nor committed to any activity that would confirm effectiveness of the Water Chemistry Program to mitigate erosion in the stainless steel CVCS high-pressure pump minimum flow orifice.

By letter dated March 7, 2011, the staff issued RAI 3.2.2.2.6-02 asking the applicant to include in the AMP(s) for these components an inspection or testing activity to confirm effectiveness of the Water Chemistry Program to mitigate or prevent unacceptable loss of material due to erosion in the stainless steel CVCS high-pressure pump minimum flow orifices.

In its response dated April 5, 2011, the applicant stated that it will credit its high-pressure SI pump (CVCS charging pump) TS Performance Monitoring Program to detect loss of material due to erosion in the minimum flow orifices and to confirm effectiveness of the Water Chemistry Program for this component. The applicant stated the following:

- Its TSs require quarterly testing of the CVCS charging pump.
- The pump is always tested in the same lineup where the flow path is only through the minimum flow orifice.

- Pump flow and differential pressure are measured, recorded, and compared with acceptance criteria.
- If the minimum flow orifice should experience erosion to the extent that the acceptance criteria are not met, then restoration of the pump to operable status requires appropriate corrective actions per the Corrective Action Program.

The applicant revised the LRA by adding a plant-specific note in LRA Table 3.3.2-3, revising LRA Section 3.2.2.2.6, and adding a new commitment (Commitment No. 63) to LRA Section A.3. These changes in the LRA state that the TS Performance Monitoring Program for the high-pressure safety injection pump (CVCS charging pump) is credited to detect loss of material due to erosion in the minimum flow orifices and provide a commitment to ensure that the quarterly CVCS charging pump testing is continued during the period of extended operation. Appropriate procedures are revised to add a caution stating that an increase in CVCS charging pump minimum flow may be indicative of erosion in the minimum flow orifice.

The staff noted that SRP-LR Appendix A, Section A.1.1, states that a Performance Monitoring Program, which tests the ability of a structure or component to perform its intended function, is an acceptable method for aging management. The staff also noted that the applicant will use its existing quarterly TS Performance Monitoring Program for the CVCS high-pressure SI pump (charging pump) to confirm effectiveness of the Water Chemistry Program in mitigating or preventing unacceptable loss of material due to erosion in the stainless steel minimum flow orifices exposed to treated borated water. The staff further noted that the applicant added a new commitment (Commitment No. 63) to ensure that quarterly CVCS charging pump testing is continued during the period of extended operation.

The staff finds that the applicant has met the further evaluation criteria and that the applicant’s proposal to manage aging using the Water Chemistry Program and performance monitoring of the CVCS charging pump is acceptable for the following reasons:

- Properly maintained water chemistry will mitigate erosion in the CVCS charging pump minimum flow orifice.
- Performance monitoring will be used to ensure effectiveness of the Water Chemistry Program for this component.
- Performance monitoring is one of the four general types of AMPs recommended in SRP-LR, Appendix A.

Based on its review above, the staff finds the applicant’s responses to RAIs 3.2.2.2.6-01 and 3.2.2.2.6-02 acceptable, and the staff’s concerns described in these RAIs are resolved.

Based on the program identified, and the applicant’s commitment to monitor performance, the staff concludes that the applicant’s program meets SRP-LR Section 3.2.2.2.6 criteria. For those items that apply to LRA Section 3.2.2.2.6, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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).

3.2.2.2.7 Loss of Material Due to General Corrosion and Fouling

LRA Section 3.2.2.2.7, associated with LRA Table 3.2.1, item 3.2.1-13, addresses loss of material due to general corrosion and fouling in steel drywell and suppression chamber spray system nozzle and flow orifice exposed to air-indoor uncontrolled (internal). The applicant stated that this item is not applicable because it is only applicable to BWRs. The staff reviewed SRP and LRA Section 3.2 and noted that this item is associated only with BWRs; therefore, it finds the applicant's claim acceptable.

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 following criteria in SRP-LR Section 3.2.2.2.8:

(1) LRA Section 3.2.2.2.8.1, associated with LRA Table 3.2.1, item 3.2.1-14, addresses loss of material due to general, pitting, and crevice corrosion in BWR steel piping, piping components, and piping elements exposed to treated water. The applicant stated that this item is not applicable because it is only applicable to BWRs. The staff reviewed the SRP-LR and LRA Section 3.2 and noted that this item is associated only with BWRs; therefore, it finds the applicant's claim acceptable.

(2) LRA Section 3.2.2.2.8.2, associated with LRA Table 3.2.1, item 3.2.1-15, addresses loss of material due to general, pitting, and crevice corrosion in internal surfaces of steel containment isolation piping, piping components, and piping elements exposed to treated water. The applicant stated that this item is not applicable because its ESF systems do not contain steel containment isolation piping, piping components, and piping elements exposed to treated water. The staff reviewed LRA Sections 2.3.2 and 3.2 and the UFSAR and confirmed that no in-scope steel containment isolation piping, piping components, and piping elements exposed to treated water are present in the ESF systems; therefore, it finds the applicant's claim acceptable.

(3) LRA Section 3.2.2.2.8.3, referenced by LRA Table 3.2.1, item 3.2.1-16, addresses steel piping, piping components, and piping elements exposed to lubricating oil, 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 criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material due to general, pitting, and crevice corrosion through examination of susceptible locations in steel piping components in the RHR and SI systems. In addition, the applicant stated that the One-Time Inspection Program will also be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material due to general, pitting, and crevice corrosion through examination of susceptible locations in steel tanks in the SI system.

    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 AMP relies on periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil control should be confirmed to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to verify the effectiveness of the Lubricating Oil Program for which 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's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. In its review of components associated with item 3.2.1-16, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report. Additionally, the applicant stated that the One-Time Inspection Program will be used to examine steel piping, piping components, and piping elements to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.2.2.2.8, item 3; therefore, the applicant's AMR is consistent with the GALL Report.

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 the line items that apply to LRA Section 3.2.2.2.8.3, the staff determined that the LRA is consistent with the GALL Report, and the applicant demonstrated that the effect 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).

3.2.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

LRA Section 3.2.2.2.9 is associated with LRA Table 3.2.1, item 3.2.1-17, and addresses loss of material due to general, pitting, crevice and MIC in steel (with or without coating or wrapping) piping, piping components, and piping elements exposed to a soil environment. The applicant stated that this item is not applicable because there are no steel (with or without coating or wrapping) piping, piping components, and piping elements in the ESF systems exposed to soil. The staff reviewed LRA Sections 2.3 and 3.2 and the applicant's UFSAR and confirmed that no in-scope steel piping, piping components, and piping elements exposed to a soil environment are present in the ESF systems; therefore, it finds the applicant's determination acceptable.

3.2.2.2.10 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.2.2.3 Aging Management Review Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.2.2-1 through 3.2.2-4, 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 3.2.2-1 through 3.2.2-4, via Notes F–J, the applicant indicated which combinations of component type, material, environment, and AERM do not correspond to an 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 item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR 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 item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the 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 if the applicant 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.

3.2.2.3.1 Combustible Gas Control System—Summary of Aging Management Review—LRA Table 3.2.2-1

In LRA Tables 3.2.2-1, 3.2.2-2, 3.2.2-3, and 3.3.2-4, the applicant stated that the stainless steel bolting exposed to air-indoor is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though stainless steel bolting exposed to air-indoor is not specifically addressed in the GALL Report, Table IX.E, the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, Table IX.C of the GALL Report states that stainless steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion and cracking due to SCC. The staff noted that the environment of interest, air-indoor, would not induce SCC or loss of material in stainless steel material because stainless steel is inherently resistant to corrosion in the air-indoor environment. Therefore, the aging effect of concern is loss of preload, which is addressed in the AMR.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of material of stainless steel bolting exposed to air-indoor in the ESF system exposed to indoor air, the GALL Report has items for other material bolting exposed to air-indoor managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload. It also inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

In LRA Tables 3.2.2-1, 3.2.2-3, and 3.2.2-4, the applicant stated that for glass piping elements exposed to air-with borated water leakage (external), there is no aging effect, and no AMP is proposed. The AMR item cites generic note G. The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because the GALL Report, item V.F-9 states that for an environment of treated borated water, there is no AERM and no recommended AMP, and the air with borated water leakage environment is no more severe than the treated borated water 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 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).

3.2.2.3.2 Containment Building Spray System—Summary of Aging Management Review—LRA Table 3.2.2-2

The staff's evaluation for stainless steel bolting, exposed to air-indoor and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.2.2.3.1.

In LRA Table 3.2.2-2, the applicant stated that elastomer flexible hoses exposed to air with borated water leakage (external) are being managed for hardening and loss of strength by the External Surfaces Monitoring Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because the GALL Report, Table IX.C, indicates that elastomers are susceptible to hardening and loss of strength at temperatures over 95 °F (35 °C), which is addressed in the AMR item. The GALL Report, item VII.A3-1, also indicates that elastomers are susceptible to hardening when exposed to treated borated water.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff noted that the program includes non-visual tactile examinations, such as scratching, which will determine if scale or residues are present or determine if there is a breakdown of material. The staff also noted that the program includes bending and folding of the elastomer to detect cracking that initiates at the surface. The staff further noted that the program includes stretching and pressing to determine the resistance of the material to hardening effects and pressing to gauge the materials resiliency to maintain its strength. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the program includes periodic visual inspections as well as non-visual tactile examinations, which are capable of detecting hardening and loss of strength by detecting discontinuities and imperfections on the surface of the component.

In LRA Table 3.2.2-2, the applicant stated that the stainless steel piping and fittings exposed to air-outdoor (external) are being managed for loss of material by the External Surfaces Monitoring Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because the GALL Report, Table IX.C, states that stainless steels are susceptible to loss of material due to pitting and crevice corrosion and cracking due to SCC. The staff noted that the environment of interest, air-outdoor (external), would be expected to contain higher levels of chlorides due to the site's relative proximity to the ocean, which is known to induce SCC. By letter dated February 24, 2011, the staff issued RAI 3.3-1 requesting that the applicant explain why atmospheric chloride-induced SCC is not considered to be an applicable aging effect for stainless steel components exposed to outdoor-air and explain how SCC will be managed if it is determined to be an applicable aging affect.

In its response dated March 22, 2011, the applicant stated that SCC has been added as an aging mechanism for stainless steel components exposed to air-outdoor environment. The applicant added a new item to manage cracking by the External Surfaces Monitoring Program. The staff finds the applicant's response acceptable because the applicant has modified the LRA to include SCC as an applicable aging effect for stainless steel components exposed to outdoor-air and include SCC as an aging effect to be managed by the External Surfaces Monitoring Program, which includes visual inspection that is a capable technique to detect SCC. The staff's concern described in RAI 3.3-1 is resolved.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the program uses periodic visual inspections that would detect loss of material and detect SCC prior to loss of component-intended function.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.2.2.3.3 Residual Heat Removal System—Summary of Aging Management Review—LRA Table 3.2.2-3

The staff's evaluation for stainless steel bolting, exposed to air-indoor and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.2.2.3.1.

The staff's evaluation for glass piping elements exposed to air-with borated water leakage (external) with no AERM and no recommended AMP, citing generic note G, is documented in Section 3.2.2.3.1.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.2.2.3.4 Safety Injection System—Summary of Aging Management Review—LRA Table 3.2.2-4

The staff's evaluation for stainless steel bolting, exposed to air-indoor and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.2.2.3.1.

The staff's evaluation for glass piping elements exposed to air-with borated water leakage (external) with no AERM and no recommended AMP, citing generic note G, is documented in Section 3.2.2.3.1.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.2.3 Conclusion

The staff concludes that the applicant provided sufficient information to demonstrate that the effects of aging for the ESF systems 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).

3.3 <u>Aging Management of Auxiliary Systems</u>

This section of the SER documents the staff's review of the applicant's AMR results for the auxiliary system components and component groups of the following systems:

- auxiliary boiler
- boron recovery system
- chemical and volume control system
- chlorination system
- containment air handling system
- containment air purge system
- containment enclosure air handling system
- containment online purge system
- control building air handling system
- demineralized water system
- dewatering system
- diesel generator
- diesel generator air handling system
- emergency feed water pump house air handling system
- fire protection system
- fuel handling system
- fuel oil system
- fuel storage building air handling system
- hot water heating system
- instrument air system
- leak detection system
- mechanical seal supply system
- miscellaneous equipment system
- nitrogen gas system
- oil collection for reactor coolant pumps system
- plant floor drain system
- potable water system
- primary auxiliary building air handling system
- primary component cooling water system

- radiation monitoring system
- reactor makeup water system
- release recovery system
- resin sluicing system
- roof drains system
- sample system
- screen wash system
- service water system
- service water pump house air handling system
- spent fuel pool cooling system
- switchyard
- valve stem leak-off system
- vent gas system
- waste gas system
- waste processing liquid system
- waste processing liquid drains system

3.3.1 Summary of Technical Information in the Application

LRA Section 3.3 provides AMR results for the auxiliary system components and component groups. LRA Table 3.3.1, "Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the auxiliary 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 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 if the applicant provided sufficient information to demonstrate that it will adequately manage the effects of aging for the auxiliary systems components within the scope of license renewal and subject to an AMR 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 identified the appropriate GALL Report AMRs. SER Section 3.3.2.1 documents the staff's evaluations, and SER Section 3.0.3 documents the staff's evaluations of the AMPs.

The staff also reviewed AMRs consistent with the GALL Report for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.3.2.2 acceptance criteria. SER Section 3.3.2.2 documents the staff's evaluations.

The staff also conducted a technical review of the remaining AMRs not consistent with, or not addressed in, the GALL Report. The technical review evaluated if the applicant identified all plausible aging effects and if the aging effects listed were appropriate for the material and environment combinations specified. SER Section 3.3.2.3 documents the staff's evaluations.

For SSCs that the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR 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 3.3 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 the SRP-LR, Section 4.7 for generic guidance for meeting the requirements of 10 CFR 54.21(c)(1).	Yes	TLAA	Consistent with GALL Report (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	Consistent with GALL Report (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	Consistent with GALL Report (see SER Sections 3.3.2.2.2 and 3.3.2.3.3)
Stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution > 140 °F (> 60 °C) (3.3.1-4)	Cracking due to SCC	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (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 and stainless clad steel heat exchanger components exposed to treated water > 140 °F (> 60 °C) (3.3.1-5)	Cracking due to SCC	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to Seabrook (see SER Section 3.3.2.2.3)
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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.3.2.2.3)
Stainless steel non-regenerative heat exchanger components exposed to treated borated water > 140 °F (> 60 °C) (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	Water Chemistry and One-Time Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.4)
Stainless steel regenerative heat exchanger components exposed to treated borated water > 140 °F (> 60 °C) (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 stress corrosion cracking and cyclic loading. A plant-specific AMP is to be evaluated.	Yes	Water Chemistry and One-Time Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.4)
Stainless steel high-pressure pump casing in PWR CVCS(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	Water Chemistry and One-Time Inspection	Consistent with GALL Report (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
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 Seabrook (see SER Section 3.3.2.2.4)
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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	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	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	Lubricating Oil Analysis and One-Time Inspection	Not applicable to Seabrook (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
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	Lubricating Oil Analysis and One-Time Inspection	Consistent with GALL Report (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	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.2.7)
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) and pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	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 MIC	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	No Yes	Buried Piping and Tanks Inspection	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 MIC, and fouling	Fuel Oil Chemistry and One-Time Inspection	Yes	Fuel Oil Chemistry and One-Time Inspection Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	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 MIC, 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)

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 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 Seabrook (see SER Section 3.3.2.2.10)
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	Not applicable	Not applicable to PWRs (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	Not applicable	Not applicable to Seabrook (see SER Section 3.3.2.2.10)
Copper-alloy heating, ventilation, and air conditioning (HVAC) piping, piping components, and 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	Bolting Integrity, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or External Surfaces Monitoring	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)

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 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	Bolting Integrity, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, External Surfaces Monitoring, and Compressed Air Monitoring	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and Compressed Air Monitoring	Consistent with GALL Report (see SER Section 3.3.2.2.10)
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	Buried Piping and Tanks Inspection	Consistent with GALL Report (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	Not applicable	Not applicable to PWRs (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	Not applicable	Not applicable to PWRs (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 MIC	Fuel Oil Chemistry and One-Time Inspection	Yes	Fuel Oil Chemistry, One-Time Inspection, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.3.2.2.12)

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 lubricating oil (3.3.1-33)	Loss of material due to pitting, crevice, and MIC	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	External Surfaces Monitoring and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.3.2.2.13)
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	Water Chemistry and One-Time Inspection	Not applicable to Seabrook (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 PWRs (see SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to treated water > 140 °F (> 60 °C) (3.3.1-37)	Cracking due to SCC and IGSCC	BWR Reactor Water Cleanup System	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to treated water > 140 °F (> 60 °C) (3.3.1-38)	Cracking due to SCC	BWR SCC and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)

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 BWR spent fuel storage racks exposed to treated water > 140 °F (> 60 °C) (3.3.1-39)	Cracking due to SCC	Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
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	Not applicable	Not applicable to Seabrook (see SER section 3.3.2.1.1)
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 Seabrook (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 Seabrook (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	Consistent with GALL Report
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	Not applicable to Seabrook (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	Consistent with GALL Report
Stainless steel and stainless clad steel piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water > 140 °F (> 60 °C) (3.3.1-46)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to Seabrook (see SER section 3.3.2.1.1)

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
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 (see SER section 3.3.2.1)
Stainless steel and steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water (3.3.1-49)	Loss of material due to MIC	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to Seabrook (see SER section 3.3.2.1.1)
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
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

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 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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring	Consistent with GALL Report (see SER Section 3.3.2.1.2)
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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.3.2.1.3)
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	Consistent with GALL Report
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 and 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
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	External Surfaces Monitoring	Consistent with GALL Report
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	Consistent with GALL Report
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 and Structural Monitoring	Consistent with GALL Report (see SER section 3.3.2.1.4)
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 Seabrook (see SER section 3.3.2.1.1)
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	Not applicable	Not applicable to Seabrook (see SER section 3.3.2.1.1)
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	Fire Protection and Fuel Oil Chemistry	Consistent with GALL Report
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 Seabrook (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	Not applicable	Not applicable to Seabrook (see SER section 3.3.2.1.1)

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
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	Not applicable	Not applicable to Seabrook (see SER section 3.3.2.1.1)
Steel piping, piping components, and piping elements exposed to raw water (3.3.1-68)	Loss of material due to general, pitting, crevice, and MIC, and fouling	Fire Water System	No	Fire Water System and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	Consistent with GALL Report (see SER Section 3.3.2.1.5)
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	Fire Water System	Consistent with GALL Report (see SER Section 3.3.2.1.6)
Copper-alloy piping, piping components, and piping elements exposed to raw water (3.3.1-70)	Loss of material due to pitting, crevice, and MIC, and fouling	Fire Water System	No	Fire Water System and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	Consistent with GALL Report (see SER Section 3.3.2.1.7)
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	Compressed Air Monitoring Program	Consistent with GALL Report (see SER Section 3.3.2.1.8)
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) MIC	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

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 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 and Structural Monitoring Program	Consistent with GALL Report (see SER Section 3.3.2.1.9)
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
Elastomer seals and components exposed to raw water (3.3.1-75)	Hardening and loss of strength due to elastomer degradation and loss of material due to erosion	Open-Cycle Cooling Water System	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program	Consistent with GALL Report (see SER Section 3.3.2.1.10)
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 MIC, fouling, and lining/coating degradation	Open-Cycle Cooling Water System	No	Buried Piping and Tanks Inspection	Consistent with GALL Report (see SER Section 3.3.2.1.11)
Steel heat exchanger components exposed to raw water (3.3.1-77)	Loss of material due to general, pitting, crevice, galvanic, and MIC, and fouling	Open-Cycle Cooling Water System	No	Fire Water System	Consistent with GALL Report (see SER Section 3.3.2.1.12)
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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.3.2.1.13)

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
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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components or Bolting Integrity	Consistent with GALL Report (see SER Section 3.3.2.1.14)
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 MIC	Open-Cycle Cooling Water System	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components or Structural Monitoring	Consistent with GALL Report (see SER Section 3.3.2.1.15)
Copper-alloy piping, piping components, and piping elements, exposed to raw water (3.3.1-81)	Loss of material due to pitting, crevice, and MIC, and fouling	Open-Cycle Cooling Water System	No	Buried Piping and Tanks Inspection and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.3.2.1.16)
Copper-alloy heat exchanger components exposed to raw water (3.3.1-82)	Loss of material due to pitting, crevice, galvanic, and MIC, and fouling	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System	Consistent with GALL Report
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	Fire Water System	Consistent with GALL Report (see SER Section 3.3.2.1.17)
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

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
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
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 Seabrook (see SER section 3.3.2.1.1)
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 Seabrook (see SER section 3.3.2.1.1)
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 Seabrook (see SER section 3.3.2.1.1)
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	Boric Acid Corrosion	Consistent with GALL Report
Stainless steel and steel with stainless steel cladding piping, piping components, piping elements, tanks, and fuel storage racks exposed to treated borated water > 140 °F (> 60 °C) (3.3.1-90)	Cracking due to SCC	Water Chemistry	No	Water Chemistry and One-Time Inspection	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 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	Water Chemistry and One-Time Inspection	Consistent with GALL Report
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
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
Steel and aluminum piping, piping components, and piping elements exposed to air-indoor controlled (external) (3.3.1-95)	None	None	No	None	Consistent with GALL Report
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	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 (3.3.1-99)	None	None	No	None	Consistent with GALL Report

The staff's review of the auxiliary systems component groups followed any one of several approaches. One approach, documented in SER Section 3.3.2.1, 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 3.3.2.2, 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 3.3.2.3, 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 auxiliary systems components is documented in SER Section 3.0.3.

3.3.2.1 Aging Management Review Results 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:

- Aboveground Steel Tanks Program
- Bolting Integrity Program
- Boric Acid Corrosion Program
- Buried Piping and Tanks Inspection Program
- Closed-Cycle Cooling Water System Program
- Compressed Air Monitoring Program

- External Surfaces Monitoring Program
- Fuel Oil Chemistry Program
- Fire Protection Program
- Fire Water System Program
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program
- Lubricating Oil Analysis Program
- One-Time Inspection Program
- Open-Cycle Cooling Water System Program
- Selective Leaching of Materials Program
- ASME Code Section XI ISI, Subsections IWB, IWC, and IWD Program
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- Water Chemistry Program

LRA Tables 3.3.2-1 through 3.3.2-45 summarize AMRs for the auxiliary 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 claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine if 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 item describing how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with Notes A–E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR 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 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 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 items to verify consistency with the GALL Report and to ensure 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 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 items to verify consistency with the GALL Report. The staff also determined whether the AMR 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 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 items to verify consistency with the GALL Report. The staff confirmed whether the AMR item of the different component was applicable to the component under review and whether the exceptions to the GALL Report AMPs was 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 item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff reviewed these 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 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.

LRA Table 3.2.1, item 3.2.1-48, addresses stainless steel or stainless steel clad piping, piping components, piping elements, and tanks exposed to treated borated water greater than 140 °F (60 °C), which are being managed for cracking due to SCC. The LRA credits the Water Chemistry Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed. The associated AMR items cite generic Notes A and C.

In its review of components associated with item 3.2.1-48 for which the applicant cited generic note C, the staff noted that LRA Table 3.2.2-3 indicates that stainless steel heat exchanger components (1-RH-E-188A and 188B tubes, 1-RH-E-9A and 9B channel head, 1-RH-E-9A and 9B tube sheet, and 1-RH-E-9A and 9B tubes) are subject to cracking due to SCC. The staff also noted that the applicant stated that the aging effect is managed by the Water Chemistry Program. The staff further noted that the GALL Report does not contain a specific AMR item for cracking due to SCC of stainless steel heat exchangers exposed to treated borated water greater than 140 °F (60 °C) in the ESFs. However, the staff noted that GALL Report item VII.E1-5 addresses cracking due to SCC of stainless steel heat exchangers exposed to treated borated water greater than 140 °F (60 °C) in the auxiliary systems. Additionally, the GALL AMR item recommends to use the Water Chemistry Program and a plant-specific program that verifies the absence of cracking due to SCC. By letter dated January 5, 2011, the staff issued RAI 3.2.2.3-01 requesting that the applicant justify how the Water Chemistry Program alone is adequate to manage the aging effect for the heat exchanger components exposed to treated borated water greater than 140 °F (60 °C). As part of the justification, the staff asked the applicant to evaluate the operating experience to clarify whether it supports the AMR results. The staff also requested that, in lieu of a justification, the applicant provide a plant-specific program that will confirm the absence of cracking due to SCC in the components and verify the effectiveness of the Water Chemistry Program.

In its response dated February 3, 2011, the applicant stated that the One-Time Inspection Program will be implemented to verify the effectiveness of the Water Chemistry Program for the heat exchanger components exposed to the treated borated water greater than 140 °F (60 °C). In its response, the applicant also indicated that LRA Tables 3.2.1, 3.3.1 and 3.2.2-3 and LRA Section 3.3.2.2.4.2 were revised accordingly.

Based on its review, the staff finds the applicant's response to RAI 3.2.2.3-01 acceptable because the applicant revised the LRA so that the One-Time Inspection Program will be used to verify the effectiveness of the Water Chemistry Program for managing cracking due to SCC of the heat exchanger components in a manner that is consistent with the recommendations in the GALL Report. The staff's concern described in RAI 3.2.2.3-01 is resolved.

The staff reviewed the Water Chemistry Program and One-Time Inspection Program and the staff's evaluations are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. In its review, the staff finds the applicant's use of the Water Chemistry Program and One-Time Inspection Program acceptable to manage the aging effect for the following reasons:

- The Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate the environmental effect on the aging.
- The Water Chemistry Program also takes corrective actions if the parameters exceed the limits so that the environmental effect on the aging is minimized.
- The One-Time Inspection Program will be implemented to confirm the effectiveness of the Water Chemistry Program, consistent with the recommendations in the GALL Report.

LRA Table 3.3.1, item 3.3.1-90 addresses stainless steel piping, piping components, piping elements, tanks, and spent fuel rack supports exposed to treated borated water greater than 140 °F (60 °C) which are being managed for cracking due to SCC. The LRA credits the Water Chemistry Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note A.

In its review of components associated with item number 3.3.1-90 for which the applicant cited generic note A, the staff noted that the guidance in the SRP-LR and GALL Report was revised in LR-ISG-2011-01, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water," to add the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage stainless steel components for loss of material, cracking, and reduction of heat transfer in treated borated water environments that are not controlled to low oxygen levels. The staff noted that, prior to the issuance of LR-ISG-2011-01, the SRP-LR and GALL Report guidance inappropriately credited the boron in borated water as a corrosion inhibitor in place of other aging management activities.

By letter dated May 29, 2012, the staff issued RAI 3.2.1.48-1 requesting that the applicant describe how the effectiveness of the Water Chemistry Program to manage cracking will be verified for stainless steel components exposed to treated borated water with greater than 5 ppb oxygen. Pending the staff's review of the applicant's response, this issue is identified as Open Item OI 3.2.2.1-1.

LRA Table 3.3.1, item 3.3.1-91 addresses stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated borated water which are being managed for loss of material due to pitting and crevice corrosion. The LRA credits the Water Chemistry Program to manage the aging effect. The GALL Report recommends GALL AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed.

The associated AMR items cite generic notes A or C. The staff noted that the LRA originally included a bolting item that referenced item 3.3.1-91 in the spent fuel pool cooling system, citing generic note E; however, in its response to RAI B.2.1.9-1 in a letter dated December 17, 2010, the applicant stated that the subject bolting was not in scope for license renewal and removed the item from the LRA.

In its review of components associated with item number 3.3.1-91 for which the applicant cited generic note A or C, the staff noted that the guidance in the SRP-LR and GALL Report was revised in LR-ISG-2011-01, “Aging Management of Stainless Steel Structures and Components in Treated Borated Water,” to add the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage stainless steel components for loss of material, cracking, and reduction of heat transfer in treated borated water environments that are not controlled to low oxygen levels. The staff noted that, prior to the issuance of LR-ISG-2011-01, the SRP-LR and GALL Report guidance inappropriately credited the boron in borated water as a corrosion inhibitor in place of other aging management activities.

By letter dated May 29, 2012, the staff issued RAI 3.2.1.48-1 requesting that the applicant describe how the effectiveness of the Water Chemistry Program to manage loss of material will be verified for stainless steel components exposed to treated borated water with greater than 5 ppb oxygen. Pending the staff’s review of the applicant’s response, this issue is identified as Open Item OI 3.2.2.1-1.

The staff concludes that, pending resolution of Open Item OI 3.2.2.1-1, the applicant 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).

3.3.2.1.1 Aging Management Review Results Identified as Not Applicable

LRA Table 3.3.1, items 3.3.1-36, 3.3.1-37, 3.3.1-38, and 3.3.1-39 state that these items are applicable only to BWRs. The staff confirmed that these items do not apply because the unit is a PWR design. Based on this determination, the staff finds that the applicant provided an acceptable basis for concluding AMR items 3.3.1-36, 3.3.1-37, 3.3.1-38, 3.3.1-39, and 3.3.1-49 are not applicable.

LRA Table 3.3.1, items 3.3.1-40, 3.3.1-41, 3.3.1-42, 3.3.1-44 3.3.1-62, 3.3.1-66, 3.3.1-67, 3.3.1-86, 3.3.1-87, 3.3.1-88 state that these items are not applicable to Seabrook. The staff reviewed the LRA and UFSAR and confirmed that the applicant’s LRA does not have any AMR results that are applicable for these items.

LRA Table 3.3.1, item 3.3.1-46, addresses stainless steel and stainless steel clad steel piping components and heat exchangers exposed to closed-cycle cooling water at temperatures greater than 140 °F (60 °C). The GALL Report recommends the Closed-Cycle Cooling Water System Program to manage cracking due to SCC for this component group. The applicant stated that this item is not applicable because this item was not used. The staff evaluated the applicant’s claim and found that the primary component cooling water system contains stainless steel components exposed to closed-cycle cooling water. In addition, the staff noted that portions of the primary component cooling water system may reach temperatures greater than 140 °F (60 °C), based on information in the applicant’s UFSAR. By letter dated January 21, 2011, the staff issued RAI 3.3.1.46-1, asking the applicant to clarify whether any stainless steel components in the primary cooling water system are exposed to closed-cycle cooling water with temperatures greater than 140 °F (60 °C).

In its response dated February 18, 2011, the applicant stated that the temperatures provided for the primary component cooling water system in UFSAR Table 9.2-7, for the thermal barrier loop heat exchangers, are design temperatures associated with an abnormal event. The applicant also stated that, during normal power operation, the heat exchanger inlet temperature is approximately 86 °F and since the thermal barrier cooling water does not exceed 140 °F, SCC does not need to be addressed in this system. The staff finds the applicant's response and its claim, that this item is not applicable, acceptable because abnormal events need not be postulated for license renewal, as stated in SRP-LR Section A.1.2.1, "Applicable Aging Effects." Therefore, the components will not reach temperatures requiring consideration of SCC. The staff's concern described in RAI 3.3.1.46-1 is resolved.

LRA Table 3.3.1, item 3.3.1-49, addresses stainless steel and stainless steel clad heat exchanger components exposed to closed-cycle cooling water. The GALL Report recommends the Closed-Cycle Cooling Water Program to manage loss of material due to MIC for this component group. The applicant stated that this item is not applicable because the GALL Report only includes items associated with BWR systems, and Seabrook is a PWR. The staff evaluated the applicant's claim and found it acceptable because the applicant manages the relevant components for loss of material for other aging mechanisms with the Closed-Cycle Cooling Water Program, consistent with the guidance in the GALL Report, which will identify loss of material due to MIC. This issue is also addressed in RAI B.2.1.12-7, which is discussed in SER Section 3.0.3.2.4.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and 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 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).

LRA Table 3.3.1, item 3.3.1-63, addresses steel fire rated doors exposed to air-outdoor or air-indoor uncontrolled. The GALL Report recommends the Fire Protection Program to manage loss of material due to wear for this component group. The applicant stated that this item is not applicable in the auxiliary system; however, loss of material due to wear of steel fire doors exposed to air-outdoor or air-indoor uncontrolled is managed by the Fire Protection Program, as described in LRA Section 3.5. The staff evaluated the applicant's claim and found it acceptable because steel fire doors were not found in the auxiliary system, and for these components in the containment, structures, and component system described in LRA Section 3.5, the applicant will manage aging with the Fire Protection Program, which is consistent with the guidance in the GALL Report.

LRA Table 3.3.1, item 3.3.1-65, addresses reinforced concrete structural fire barriers, walls, ceilings, and floors exposed to air-indoor uncontrolled, which are being managed for concrete cracking and spalling due to aggressive chemical attack and reaction with aggregates. LRA Table 3.3.1, item 3.3.1-67, addresses reinforced concrete structural fire barriers, walls, ceilings, and floors exposed to air-indoor uncontrolled, which are being managed for loss of material due to corrosion of embedded steel. The GALL Report recommends the Fire Protection and

Structures Monitoring Programs to manage concrete cracking and spalling due to aggressive chemical attack and reaction with aggregates and loss of material due to corrosion of embedded steel for this component group. The applicant stated that these items are not applicable to the auxiliary system but are applicable to the containment, structures, and component supports described in LRA Section 3.5. The staff evaluated the applicant's claim and noted that, in LRA Tables 3.5.2-4, 3.5.2-5, and 3.5.2-8, the applicant cited LRA Table 3.3.1, item 3.3.1-65 or 3.3.1-67 when the Fire Protection Program is proposed to manage aging for reinforced concrete structural fire barriers, and LRA Table 3.3.1, item 3.5.1-23, when the Structures Monitoring Program is proposed to manage aging. The staff also noted that, in Table 3.5.2-2, the applicant uses the ASME Code Section XI, Subsection IWL Program to manage concrete cracking and spalling using LRA Table 3.5.1, item 3.5.1-1, instead of the Structures Monitoring Program. The staff reviewed the applicant's ASME Code Section XI, Subsection IWL Program, and its evaluation is documented in SER Section 3.0.3.2.17. The staff further noted that the applicant's ASME Code Section XI, Subsection IWL Program includes the same or more conservative inspection method and frequency as the Structures Monitoring Program. The staff finds the applicant's claim acceptable because there are no reinforced structural fire barriers, walls, ceilings, and floors in the auxiliary systems, and these components in the containment, structures, and component supports portion of the LRA are either being managed by the Fire Protection and Structures Monitoring Programs or by acceptable alternative items.

3.3.2.1.2 Loss of Material Due to Pitting and Crevice Corrosion

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, which are being managed for loss of material due to pitting and crevice corrosion. Stainless steel piping components exposed to external condensation are being managed for loss of material due to pitting and crevice corrosion. The LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect for internal condensation and the External Surfaces Monitoring Program to manage the aging effect for external condensation. The GALL Report recommends GALL Report AMP XI.M24, "Compressed Air Monitoring" to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E.

GALL Report AMP XI.M24 recommends using visual inspections of stainless and carbon steels to detect the effects of corrosion or presence of contaminants. In its review of components associated with LRA Table 3.3.1, item 3.3.1-54, for which the applicant cited generic note E, the staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or the External Surfaces Monitoring Program proposes to manage the aging of piping and fittings, valve bodies, tanks, traps, flexible hoses, and orifices through the use of visual surface inspections (during periodic maintenance and via work order for components identified as requiring aging management) for evidence of hardening and loss of strength, loss of material, and reduction of heat transfer due to fouling.

The staff's evaluations of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and the External Surfaces Monitoring Program are documented in SER Sections 3.0.3.2.15 and 3.0.3.2.14, respectively. In its review of components associated with LRA Table 3.3.1, item 3.3.1-54, the staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for stainless steel compressed air system piping, piping components, and piping elements exposed to internal condensation, and the External Surfaces Monitoring Program for stainless steel piping components exposed to external condensation acceptable. These programs will manage loss of material for the relevant in-scope stainless steel components through visual inspections which will be performed by qualified personnel during the performance of periodic, predictive, and corrective maintenance and surveillance testing.

The staff concludes that the applicant 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 Material Due to General Corrosion

LRA Table 3.3.1, item 3.3.1-56, addresses steel HVAC ducting and components external surfaces exposed to air-indoor uncontrolled (external), which are being managed for loss of material due to general corrosion. The applicant credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect for steel fan housings exposed to air-indoor uncontrolled (internal). The GALL Report recommends GALL Report AMP XI.M36, “External Surfaces Monitoring,” to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E. The applicant stated that components that have the same internal and external environments have the same aging effects on both the internal and external surfaces.

GALL Report AMP XI.M36 recommends using visual inspections of the external surfaces of components for general corrosion to manage the aging effect for the item. In its review of components associated with LRA Table 3.3.1, item 3.3.1-56, 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 the aging of structures and structural components through the use of opportunistic inspections of the internal surfaces of components. The staff also noted that, since the components have the same internal and external environments, the loss of material aging effect is the same on both the internal and external surfaces; therefore, GALL Report, item VII.F4-1, which refers to air-indoor uncontrolled (external) environment and the loss of material aging mechanism, would also apply to an air-indoor uncontrolled (internal) environment.

The staff’s evaluation of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program is documented in SER Section 3.0.3.2.15. In its review of components associated with LRA Table 3.3.1, item 3.3.1-56, the staff finds the applicant’s proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program acceptable because it includes visual inspections that can detect loss of material on the internal surfaces of components.

The staff concludes that the applicant 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).

3.3.2.1.4 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 uncontrolled, which are being managed for increased hardness, shrinkage, and loss of strength due to weathering. The applicant credits the Fire Protection or

Structures Monitoring Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M26, "Fire Protection," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note A when they are managed by the Fire Protection Program and generic note E when they are managed by the Structures Monitoring Program.

GALL Report AMP XI.M26 recommends using visual inspections for 10 percent of each type of seal at least once every RFO to manage the aging of these items. In its review of components associated with LRA Table 3.3.1, item 3.3.1-61, for which the applicant cited generic note E, the staff noted that the Structures Monitoring Program will be used to manage the aging of elastomer seals through the use of visual inspections performed on a 5-year basis.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. In its review of components associated with LRA Table 3.3.1, item 3.3.1-61, the staff noted that the components which cite generic note E and do not have a corresponding item that credits the Fire Protection Program are not fire barriers but other types of elastomer seals, such as pressure or flood barriers. The staff also noted that LRA Table 3.3.1, item 3.3.1-61, is specifically for fire barrier elastomer seals, and the Fire Protection Program is not applicable for non-fire barrier elastomer seals. The staff further noted that non-fire barrier elastomer seals may be constructed of materials that are sensitive to ultraviolet light, radiation, or ozone; therefore, tactile examination techniques—such as scratching, bending, folding, stretching or pressing—are recommended in conjunction with visual examinations to manage the effects of aging. The applicant's Structures Monitoring Program does not include tactile examination techniques. By letter dated January 21, 2011, the staff issued RAI 3.3.1.61-1 requesting that the applicant clarify whether the non-fire barrier elastomer seals being managed for aging by the Structures Monitoring Program are subject to hardening and loss of strength due to exposure to ultraviolet light, radiation, or ozone. If the materials are subject to hardening and loss of strength and exposed to these aging effects, the staff asked the applicant to explain how the Structures Monitoring Program is adequate to manage aging for these components.

In its response dated February 18, 2011, the applicant stated that the Structures Monitoring Program manages non-fire barrier elastomer seals that are subject to aging effects of increased hardness, shrinkage, and loss of strength for all environments including ultraviolet light, radiation, and ozone. The applicant also stated that it will perform both visual and tactile examinations, when required, for non-fire barrier elastomer seals to ensure the seal's integrity. The applicant further stated that the Structures Monitoring Program will be updated to provide tactile examination techniques for the non-fire barrier elastomer seals. The staff finds the applicant's response acceptable because the applicant will enhance its Structures Monitoring Program to include tactile examination techniques for the non-fire barrier elastomer seals, which is an appropriate technique for managing the hardening and loss of strength and is consistent with the GALL Report recommendations. The staff's concern described in RAI 3.3.1.61-1 is resolved.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. In its review of components associated with item 3.3.1-61, the staff noted that the components that cite generic note E and do not have a corresponding item being managed by the Fire Protection Program, are not fire barriers but are other types of elastomer seals, such as pressure or flood barriers. The staff also noted that item 3.3.1-61 is specifically for fire barrier elastomer seals, and the Fire Protection Program is not applicable for non-fire barrier elastomer seals. The staff finds the applicant's proposal to manage non-fire barrier elastomer seals using the Structures Monitoring Program acceptable because the program includes visual inspections and tactile examinations, which are capable of detecting increased hardness, shrinkage, and loss of strength for elastomer seals.

The staff concludes that the applicant 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).

3.3.2.1.5 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, which are being managed for loss of material due to general, pitting, crevice, and MIC and fouling. The staff noted that the LRA states that galvanic corrosion is an additional aging effect that will be managed for several systems. The LRA credits the Fire Water System to manage the aging effects for components in the fire protection system and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effects for components in the chlorination, dewatering, plant floor drain, potable water, roof drains, screen wash, waste processing liquid, and waste processing liquid drains systems. The GALL Report recommends GALL Report AMP XI.M27, “Fire Water System,” to ensure that these aging effects are adequately managed. The associated AMR items that credit the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program cite generic note E and plant-specific notes that state the components are not associated with the fire water system.

GALL Report AMP XI.M27 recommends using non-intrusive examination techniques (e.g., volumetric testing) to detect changes in the wall thickness. GALL Report AMP XI.M27 also recommends visual inspections of the interior pipe surfaces as an alternative to non-intrusive examinations, as long as inspections are performed on a representative number of locations on a reasonable basis and can evaluate wall thickness and the inner diameter of the piping to manage the aging of these items. In its review of components associated with LRA Table 3.3.1, item 3.3.1-68, 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 the aging of steel piping, piping components, and piping elements through the use of visual inspections performed on an opportunistic basis.

The staff’s evaluation of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff noted that LRA Table 3.3.1, item 3.3.1-68, states that loss of material due to fouling is not an applicable aging effect for components in the potable water system. However, the staff also noted that GALL Report Table 3, item 68, states that steel components exposed to raw water have an aging effect of loss of material due to fouling. While the applicant has stated that the environment is potable water, given that there are no chemistry controls for its potable water, its effect on items would be similar to raw water. Nevertheless, the staff also noted that the inspections performed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for loss of material due to corrosion are the same as those to identify loss of material due to fouling. In its review of components associated with LRA Table 3.3.1, item 3.3.1-68, the staff finds the applicant’s proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable. This program will conduct visual inspections of the internal surfaces of the components, which is equivalent to the recommendations in GALL Report AMP XI.M27 for managing aging of these types of components.

The staff concludes that the applicant 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 Pitting and Crevice Corrosion and Fouling

LRA Table 3.3.1, item 3.3.1-69, addresses stainless steel piping, piping components, and piping elements exposed to raw water, which are being managed for loss of material due to pitting and crevice corrosion and fouling. The staff noted that the LRA states that MIC is an additional aging effect that will be managed for a few systems. The LRA credits the Fire Water System Program to manage the aging effects for components in the fire protection system and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effects for components in the plant floor drain, potable water, and waste processing liquid drains systems. The GALL Report recommends GALL Report AMP XI.M27, “Fire Water System,” to ensure that these aging effects are adequately managed. The associated AMR items that credit the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M27 recommends using non-intrusive examination techniques (e.g., volumetric testing) to detect changes in the wall thickness. GALL Report AMP XI.M27 also recommends visual inspections of the interior pipe surfaces as an alternative to non-intrusive examinations, as long as inspections are performed on a representative number of locations on a reasonable basis and can evaluate wall thickness and the inner diameter of the piping to manage the aging of these items. In its review of components associated with LRA Table 3.3.1, item 3.3.1-69, 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 the aging of stainless steel piping, piping components, and piping elements through the use of visual inspections performed on an opportunistic basis.

The staff’s evaluation of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff noted that LRA Table 3.3.1, item 3.3.1-69, states that loss of material due to fouling is not an applicable aging effect for components in the potable water system. However, the staff also noted that GALL Report Table 3, item 69, states that steel components exposed to raw water have an aging effect of loss of material due to fouling. While the applicant has stated that the environment is potable water, given that there are no chemistry controls for its potable water, its effect on items would be similar to raw water. Nevertheless, the staff also noted that the inspections performed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for loss of material due to corrosion are the same as those to identify loss of material due to fouling. In its review of components associated with LRA Table 3.3.1, item 3.3.1-69, the staff finds the applicant’s proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable. This program will conduct visual inspections of the internal surfaces of components, which is equivalent to the recommendations in GALL Report AMP XI.M27 for managing aging of these types of components.

The staff concludes that the applicant 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 Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

LRA Table 3.3.1, item 3.3.1-70, addresses copper piping, piping components, and piping elements exposed to raw water, which are being managed for loss of material due to pitting, crevice, and MIC and fouling. The staff noted that the LRA states that this item will manage the additional aging effect of galvanic corrosion for components in the potable water system. The LRA credits the Fire Water System Program to manage the aging effects for components in the fire protection system and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effects for components in the potable water system. The GALL Report recommends GALL Report AMP XI.M27, “Fire Water System,” to ensure that these aging effects are adequately managed. The associated AMR items, which credit the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M27 recommends using non-intrusive examination techniques (e.g., volumetric testing) to detect changes in the wall thickness. GALL Report AMP XI.M27 also recommends visual inspections of the interior pipe surfaces as an alternative to non-intrusive examinations, as long as inspections are performed on a representative number of locations on a reasonable basis and can evaluate wall thickness and the inner diameter of the piping to manage the aging of these items. In its review of components associated with LRA Table 3.3.1, item 3.3.1-70, for which the applicant cited generic note E, the staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program also proposes to manage the aging of copper piping, piping components, and piping elements through the use of visual inspections performed on an opportunistic basis.

The staff’s evaluation of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff noted that LRA Table 3.3.1, item 3.3.1-70, states that loss of material due to fouling is not an applicable aging effect for components in the potable water system. However, the staff also noted that GALL Report Table 3, item 70, states that steel components exposed to raw water have an aging effect of loss of material due to fouling. While the applicant has stated that the environment is potable water, given that there are no chemistry controls for its potable water, its effect on items would be similar to raw water. Nevertheless, the staff also noted that the inspections performed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for loss of material due to corrosion are the same as those to identify loss of material due to fouling. In its review of components associated with LRA Table 3.3.1, item 3.3.1-70, the staff finds the applicant’s proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable. This program will conduct visual inspections of the internal surfaces of components, which is equivalent to the recommendations in GALL Report AMP XI.M27 for managing aging of these types of components.

The staff concludes that the applicant 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).

3.3.2.1.8 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-71, addresses piping components, and piping elements exposed to moist air or condensation (internal), which are being managed for loss of material due to general, pitting, and crevice corrosion. The applicant credits the Compressed Air Monitoring Program to manage aging for steel and gray cast iron dryer housing, piping and fittings, trap, filter housing, and valve body components. The GALL Report recommends the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program to ensure that the aging effect is adequately managed. The associated AMR items cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The associated AMR items also cite a plant-specific note, which states that the Compressed Air Monitoring Program is substituted to manage the aging effect applicable to this component type, material, and environment combination because the diesel generator starting air is part of the Compressed Air Monitoring Program at the station. Therefore, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program is not applicable.

GALL Report AMP XI.M38 recommends using periodic visual inspections of internal surfaces. In its review of components associated with LRA Table 3.3.1, item 3.3.1-71, for which the applicant cited generic note E, the staff noted that the Compressed Air Monitoring Program also proposes to manage the aging of steel piping, piping components, and piping elements exposed to moist air or condensation (internal) through the use of air quality monitoring and visual inspections.

The staff's evaluation of the applicant's Compressed Air Monitoring Program is documented in SER Section 3.0.3.2.6. The Compressed Air Monitoring Program proposes to manage the aging of steel components by monitoring air quality and dew point and performing visual inspections. The Compressed Air Monitoring Program includes in-line dew point monitors, which verify the dew point of instrument air to be sure it is within the calculated limit and in-line filters which limit air particle size. The Compressed Air Monitoring Program also includes air sampling to ensure compliance with air quality standards. In addition, the applicant stated that the system is subject to a New Hampshire State inspection, which is a visual inspection of the system. In its review of components associated with LRA Table 3.3.1, item 3.3.1-71, the staff finds the applicant's proposal to manage aging using the Compressed Air Monitoring Program acceptable because, like the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, it will perform visual inspections that can detect loss of material prior to the loss of component function.

The staff concludes that the applicant 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).

3.3.2.1.9 Loss of Material Due to General Corrosion

LRA Table 3.3.1, item 3.3.1-73, addresses steel crane structural girders in load handling system exposed to air-indoor uncontrolled (external), which are being managed for loss of material due to general corrosion. The LRA credits the Inspection of Overhead Heavy Load and Light Load

(Related to Refueling) Handling Systems and Structural Monitoring Programs to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems," to ensure that this aging effect is adequately managed. The associated AMR items cite generic note E and plant-specific note 514, which states that the applicant will use the Structural Monitoring Program in addition to the recommended GALL Report AMP.

For those items associated with generic note E, GALL Report AMP XI.M23 recommends using visual inspections on a routine basis to manage the aging of these items. In its review of components associated with item 3.3.1-73, for which the applicant cited generic note E, the staff noted that the Structural Monitoring Program also includes the use of visual inspections to manage the aging of steel crane structural girders in the load handling system.

The staff's evaluation of the applicant's Structural Monitoring Program is documented in SER Section 3.0.3.2.18. The staff noted that the applicant is using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program, documented in SER Section 3.0.3.2.5, as well as the Structural Monitoring Program, and visual inspections are included in both programs. The staff also noted the Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program performs visual inspections of structural supports of overhead cranes yearly, while the Structures Monitoring Program determines the frequency of the inspections in accordance with the characteristics of the environment in which the structures are located. For structures in harsh environments, the inspections are conducted on a 5-year basis and those in mild environments are done on a 10-year basis.

In its review of components associated with item 3.3.1-73, the staff finds the applicant's proposal to manage aging using dual programs, the Structural Monitoring Program and the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program, acceptable. Visual inspections of cranes structural components' will be performed at least annually to manage their aging effects so they can continue to fulfill their function(s) for the period of extended operation.

The staff concludes that the applicant 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 Hardening and Loss of Strength Due To Elastomer Degradation; Loss of Material Due To Erosion

LRA Table 3.3.1, item 3.3.1-75, addresses elastomer seals and components exposed to raw water, which are being managed for hardening and loss of strength due to elastomer degradation and loss of material due to erosion. The applicant credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, GALL Report AMP XI.M20 recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.3.1, item 3.3.1-75, for which the applicant cited generic note E, the staff noted that the applicant also proposed to use the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging of elastomer seals and components through the use of periodic inspection on the internal surfaces of components. It was not clear to the staff how the opportunistic visual inspections will be able to manage aging of components in a raw water system that does not include chemical treatments or surveillances. By letter dated January 5, 2011, the staff issued RAI 3.3.2.2-1 asking the applicant to justify using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, which is only a visual inspection program, to manage aging in the raw water environment.

In its response dated February 3, 2011, the applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was chosen because the internal raw water environments are not covered by any other AMP. The applicant also stated that its conclusion to use this AMP is supported by information in Revision 2 to the GALL Report, that this program applies to components exposed to any water systems not included in the open-cycle cooling water, closed treated water, or fire water AMPs. The applicant further stated that its equipment inspections have been successful at identifying and resolving corrosion or degradation before it affects the ability of the component to perform its intended function. The staff finds the applicant’s response acceptable because the GALL Report, Revision 2, allows components exposed to raw water, that are not part of the open-cycle cooling water system, to be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component Program; therefore, the applicant’s proposal complies with the current staff position. The staff’s concern described in RAI 3.3.2.2-1 is resolved.

The staff’s evaluation of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. In its review of components associated with LRA Table 3.3.1, item 3.3.1-75, the staff finds the applicant’s proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, and the response to RAI 3.3.2.2-1, acceptable for the following reasons:

- The program conducts inspections during periodic system surveillances or maintenance activities when internal surfaces are accessible.
- The inspections consist of visual examinations and non-visual examinations, such as tactile techniques that are capable of detecting hardening and loss of strength in elastomers.
- The raw water environment is associated with groundwater that is not capable of being chemical treated or for which there are no applicable performance tests associated with groundwater dewatering systems, as related to managing the aging of elastomers.

In addition, the staff finds that the use of Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable to manage the elastomers exposed to raw water because the raw water is associated with the dewatering system and not the open-cycle cooling system, so the use of this program is consistent with the current staff position. The staff’s concern described in RAI 3.3.2.2-1 is resolved.

The staff concludes that the applicant 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 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion, Fouling, and Lining/Coating Degradation

LRA Table 3.3.1, item 3.3.1-76, addresses steel piping, piping components, and piping elements (without lining or coating or with degraded lining or coating) exposed to raw water, which are being managed for loss of material due to general, pitting, and crevice corrosion, MIC, fouling, and lining or coating degradation. The applicant credits the Buried Piping and Tanks Inspection Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M.20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR item cites generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M.20 recommends using coatings to protect the metal surfaces from being exposed to aggressive environments and visual inspections to manage the aging of these items. In its review of components associated with LRA Table 3.3.1, item 3.3.1-76, for which the applicant cited generic note E, the staff noted that the Buried Piping and Tanks Inspection Program proposes to manage the aging of steel piping, piping components, and piping elements through the use of coatings to protect the metal surfaces from being exposed to aggressive environments and visual inspections.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.3.1. The staff noted that the raw water that this item is exposed to is groundwater seepage into a vault in which the piping is routed. In its review of components associated with LRA Table 3.3.1, item 3.3.1-76, the staff finds the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program acceptable for the following reasons:

- The program includes preventive actions, such as external coatings and wrappings, installed to industry standard practices.
- Periodic visual inspections will be performed starting 10 years prior to the period of extended operation and extend into both 10-year periods during the period of extended operation to ensure that coatings remain intact.
- Plant-specific operating experience will be used to inform inspection locations.

The staff concludes that the applicant 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).

3.3.2.1.12 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion, and Fouling

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, and crevice corrosion, MIC, and fouling. The applicant credits the Fire Water System Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle

Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, GALL Report AMP XI.M20 recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.3.1, item 3.3.1-77, for which the applicant cited generic note E, the staff noted that the Fire Water System Program proposes to manage the aging of steel heat exchanger components through the use of inspections, periodic flushing, system performance testing, and chemical additions to prevent microbiological growth.

The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.2.8. In its review of components associated with LRA Table 3.3.1, item 3.3.1-77, the staff finds the applicant's proposal to manage aging using the Fire Water System Program acceptable because the program conducts inspections roughly every outage and uses preventive actions, including chemical additions and performance verification.

The staff concludes that the applicant 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).

3.3.2.1.13 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-78, addresses stainless steel, nickel alloy, and copper-alloy piping, piping components, and piping elements exposed to raw water, which are being managed for loss of material due to pitting and crevice corrosion. The applicant credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, GALL Report AMP XI.M20 recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.3.1, item 3.3.1-78, 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 the aging of stainless steel, nickel alloy, and copper-alloy piping, piping components, and piping elements through the use of periodic inspection on the internal surfaces of components. It was not clear to the staff how the opportunistic visual inspections will be able to manage aging of components in a raw water system that does not include chemical treatments or surveillances. By letter dated January 5, 2011, the staff issued RAI 3.3.2.2-1 requesting that the applicant justify the use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, which is only a visual inspection program, to manage aging in the raw water environment.

In its response dated February 3, 2011, the applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was chosen because the internal raw water environments are not covered by any other AMP. The applicant also stated that its conclusion to use this AMP is supported by information in Revision 2 to the GALL Report, that this program applies to components exposed to any water systems not included in the open-cycle cooling water, closed treated water, or fire water AMPs. The applicant further stated that its equipment inspections have been successful at identifying and resolving corrosion or degradation before it affects the ability of the component to perform its intended function. The staff finds the applicant's response acceptable because the GALL Report, Revision 2, allows components exposed to raw water, that are not part of the open-cycle cooling water system, to be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component Program; therefore, the applicant's proposal complies with the current staff position. The staff's concern described in RAI 3.3.2.2-1 is resolved.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. In its review of components associated with LRA Table 3.3.1, item 3.3.1-78, the staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable. The program conducts visual inspections during periodic system surveillances or maintenance activities when internal surfaces are accessible and monitors parameters such as corrosion, corrosion byproducts, coating degradation, scale/deposits, pits, and surface discoloration and discontinuities. In addition, the staff finds that the use of Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable to manage these components exposed to raw water because the raw water is associated with the chlorination and screen wash system and not the open-cycle cooling system. Therefore, the use of this program is consistent with the current staff position.

The staff concludes that the applicant 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).

3.3.2.1.14 Loss of Material Due to Pitting and Crevice Corrosion, and Fouling

LRA Table 3.3.1, item 3.3.1-79, addresses stainless steel piping, piping components, and piping elements exposed to raw water, which are being managed for loss of material due to pitting and crevice corrosion, and fouling. The applicant credits either the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or Bolting Integrity Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, GALL Report AMP XI.M20 recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.3.1, item 3.3.1-79, 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 the aging of stainless steel piping, piping components, and piping elements through the use of periodic inspection on the internal surfaces of components. The staff also noted that the Bolting Integrity Program proposes to manage the aging of stainless steel bolts through the use of periodic inspection.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. The staff notes that the GALL Report mainly recommends managing aging of bolts with the Bolting Integrity Program. In its review of components associated with LRA Table 3.3.1, item 3.3.1-79, the staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because it follows the ASME Code guidelines for managing aging of bolts, which incorporates operating experience specifically for this component type.

For the components other than bolting, it was not clear to the staff how the opportunistic visual inspections will be able to manage aging of components in a raw water system that does not include chemical treatments or surveillances. By letter dated January 5, 2011, the staff issued RAI 3.3.2.2-1 requesting that the applicant justify the use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, which is only a visual inspection program to manage aging in the raw water environment.

In its response dated February 3, 2011, the applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was chosen because the internal raw water environments are not covered by any other AMP. The applicant also stated that its conclusion to use this AMP is supported by information in Revision 2 to the GALL Report, that this program applies to components exposed to any water systems not included in the open-cycle cooling water, closed treated water, or fire water AMPs. The applicant further stated that its equipment inspections have been successful at identifying and resolving corrosion or degradation before it affects the ability of the component to perform its intended function. The staff finds the applicant's response acceptable because the GALL Report, Revision 2, allows for components exposed to raw water, that are not part of the open-cycle cooling water system, to be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component Program. therefore, the applicant's proposal complies with the current staff position. The staff's concern described in RAI 3.3.2.2-1 is resolved.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. In its review of components associated with LRA Table 3.3.1, item 3.3.1-79, the staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable. This program conducts visual inspections during periodic system surveillances or maintenance activities when internal surfaces are accessible and monitors parameters such as corrosion, corrosion byproducts, coating degradation, scale/deposits, pits, and surface discoloration and discontinuities. In addition, the staff finds that the use of Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable to manage the component exposed to raw water because the raw water is associated with the dewatering, service water, and screen wash systems and not the open-cycle cooling system. Therefore, the use of this program is consistent with the current staff position.

The staff concludes that the applicant 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).

3.3.2.1.15 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion

LRA Table 3.3.1, item 3.3.1-80, addresses stainless steel and copper piping, piping components, and piping elements exposed to raw water, which are being managed for loss of material due to pitting and crevice corrosion and MIC. The applicant credits either the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or Structures Monitoring Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, GALL Report AMP XI.M20 recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.3.1, item 3.3.1-80, 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 the aging of stainless steel and copper piping, piping components, and piping elements through the use of periodic inspection on the internal surfaces of components. The staff also noted that the Structures Monitoring Program proposes to manage the aging of stainless steel sumps through the use of periodic inspections conducted on a 5-year basis. It was not clear to the staff how the opportunistic visual inspections will be able to manage aging of components in a raw water system that does not include chemical treatments or surveillances. By letter dated January 5, 2011, the staff issued RAI 3.3.2.2-1 requesting that the applicant justify the use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, which is only a visual inspection program to manage aging in the raw water environment. In addition, by letter dated January 5, 2011, the staff issued RAI 3.5.2.5-2 requesting that the applicant justify the use of the Structures Monitoring Program, which is only a visual inspection program, to manage aging in the raw water environment.

In its response dated February 3, 2011, the applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was chosen because the internal raw water environments are not covered by any other AMP. The applicant also stated that its conclusion to use this AMP is supported by information in Revision 2 to the GALL Report, that this program applies to components exposed to any water systems not included in the open-cycle cooling water, closed treated water, or fire water AMPs. The applicant further stated that its equipment inspections have been successful at identifying and resolving corrosion or degradation before it affects the ability of the component to perform its intended function. The staff finds the applicant's response acceptable because the GALL Report, Revision 2, allows components exposed to raw water, that are not part of the open-cycle cooling water system, to be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component Program; therefore, the applicant's proposal complies with the current staff position. The staff's concern described in RAI 3.3.2.2-1 is resolved.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. In its review of components associated with LRA Table 3.3.1, item 3.3.1-80, the staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable. This program conducts inspections during periodic system surveillances or maintenance activities when internal surfaces accessible and monitors parameters such as corrosion, corrosion byproducts, coating degradation, scale/deposits, pits, and surface discoloration and discontinuities. In addition, the staff finds that the use of Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable to manage these components exposed to raw water because the raw water is associated with the boron recovery and waste processing liquid and waste processing liquid systems and not the open-cycle cooling system. Therefore, the use of this program is consistent with the current staff position

In its response dated February 3, 2011, with regard to RAI 3.5.2.5-2, the applicant stated that the raw water in the sumps is not part of the open-cycle cooling water system and receives no chemical addition. The applicant also stated that the sumps are normally dry or slightly wetted and, if water enters the lined or unlined sumps, the sump pump removes the water. The applicant further stated that because the sumps can be wetted, it was assumed that they are in a raw water environment, that the Structures Monitoring Program will perform an inspection for degradation, and that any degradation identified will be appropriately dispositioned. The staff finds the applicant's response acceptable because the sumps are typically not wet, and the applicant conservatively assigned a raw water environment. In addition, the staff finds the response acceptable because the GALL Report, Revision 2, allows components exposed to raw water, that are not part of the open-cycle cooling water system, to be managed with programs that periodically inspect the components. The staff notes that the Structures Monitoring Program will conduct periodic visual inspections that are consistent with the current staff position in GALL Report, Revision 2. The staff's concern described in RAI 3.5.2.5-2 is resolved.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. In its review of components associated with LRA Table 3.3.1, item 3.3.1-80, the staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because the program conducts periodic visual inspections for aging effects specific to each structure by qualified individuals. In addition, the staff finds that the use of Structures Monitoring Program is acceptable to manage these components exposed to raw water because the raw water is not the open-cycle system; therefore, the use of this program is consistent with the current staff position.

The staff concludes that the applicant 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).

3.3.2.1.16 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 piping, piping components, and piping elements exposed to raw water, which are being managed for loss of material due to pitting and crevice corrosion, MIC, and fouling. The applicant credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, GALL Report AMP XI.M20 recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.3.1, item 3.3.1-81, 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 the aging of copper piping, piping components, and piping elements through the use of periodic inspection on the internal surfaces of components. It was not clear to the staff how the opportunistic visual inspections will be able to manage aging of components in a raw water system that does not include chemical treatments or surveillances. By letter dated January 5, 2011, the staff issued RAI 3.3.2.2-1 requesting that the applicant justify the use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, which is only a visual inspection program, to manage aging in the raw water environment.

In its response dated February 3, 2011, the applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was chosen because the internal raw water environments are not covered by any other AMP. The applicant also stated that its conclusion to use this AMP is supported by information in Revision 2 to the GALL Report, that this program applies to components exposed to any water systems not included in the open-cycle cooling water, closed treated water, or fire water AMPs. The applicant further stated that its equipment inspections have been successful at identifying and resolving corrosion or degradation before it affects the ability of the component to perform its intended function. The staff finds the applicant’s response acceptable because the GALL Report, Revision 2, allows components exposed to raw water, that are not part of the open-cycle cooling water system, to be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component Program; therefore, the applicant’s proposal complies with the current staff position. The staff’s concern described in RAI 3.3.2.2-1 is resolved.

The staff’s evaluation of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. In its review of components associated with LRA Table 3.3.1, item 3.3.1-81, the staff finds the applicant’s proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable. This program conducts visual inspections during periodic system surveillances or maintenance activities when internal surfaces are accessible and monitors parameters such as corrosion, corrosion byproducts, coating degradation, scale/deposits, pits, and surface discoloration and discontinuities. In addition, the staff finds that the use of Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable to manage these components exposed to raw water because the raw water is associated with the chlorination, dewatering, plant floor drain, and screen wash systems and not the open-cycle cooling system. Therefore, the use of this program is consistent with the current staff position.

The staff noted that, in a letter dated November 15, 2010, the applicant submitted Supplement 2 to the LRA. In this supplement, LRA Table 3.3.1, item 3.3.1-81, was modified to include the Buried Piping and Tanks Inspection Program for copper-alloy components. The staff also noted that LRA Table 3.3.2-37 identifies the specific components as copper alloy greater than 15 percent zinc valve bodies that are inside a vault and exposed to raw water due to groundwater inleakage as stated in plant-specific note 9. The staff further noted that, given that the valves are constructed of copper alloy greater than 15 percent zinc, they would also be susceptible to selective leaching. The staff noted that, in Table 3.3.2-37, the applicant established an item for these components that identifies selective leaching as an AERM and uses the Selective Leaching Program to manage this aging effect. The staff finds that the applicant is appropriately managing the added components because they are managing aging due loss of material and selective leaching.

For the copper alloy greater than 15 percent zinc valve body items associated with generic note E, GALL Report AMP XI.M.20 recommends using coatings to protect the metal surfaces from being exposed to aggressive environments and visual inspections to manage the aging of these items. In its review of components associated with LRA Table 3.3.1, item 3.3.1-81 for which the applicant cited generic note E, the staff noted that the Buried Piping and Tanks Inspection Program proposes to manage the aging of piping, piping components, and piping elements through the use of coatings to protect the metal surfaces from being exposed to aggressive environments and visual inspections.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.3.1. In its review of components associated with LRA Table 3.3.1, item 3.3.1-81, the staff finds the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program acceptable for the following reasons:

- The program includes preventive actions such as external coatings and wrappings installed to industry standard practices.
- Periodic visual inspections will be performed starting 10 years prior to the period of extended operation and extend into both 10-year periods during the period of extended operation to ensure that coatings remain intact.
- Plant-specific operating experience will be used to inform inspection locations.

The staff concludes that the applicant 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).

3.3.2.1.17 Reduction of Heat Transfer Due to Fouling

LRA Table 3.3.1, item 3.3.1-83, addresses stainless steel and copper-alloy heat exchanger tubes exposed to raw water, which are being managed for reduction of heat transfer due to fouling. The applicant credits the Fire Water System Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, the GALL Report AMP XI.M20 program recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.3.1, item 3.3.1-83, for which the applicant cited generic note E, the staff noted that the Fire Water System Program proposes to manage the aging of stainless steel and copper-alloy heat exchanger tubes through the use of inspections, periodic flushing, system performance testing, and chemical additions to prevent microbiological growth.

The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.2.8. In its review of components associated with LRA Table 3.3.1, item 3.3.1-83, the staff finds the applicant's proposal to manage aging using the Fire Water System Program acceptable because the program conducts inspections roughly every outage and uses preventive actions including chemical additions and performance verification.

The staff concludes that the applicant 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 Aging Management Review Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.3.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the auxiliary system components and provides 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 MIC
- loss of material due to general, pitting, crevice, MIC, 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 MIC
- loss of material due to wear
- loss of material due to cladding breach
- 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 audited and reviewed the applicant's evaluation to determine if 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 3.3.2.2. 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 states that fatigue 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 4.3 documents the staff's review of the applicant's evaluation of this TLAA.

LRA Section 3.3.2.2.1, which is associated with LRA Table 3.3.1, items 3.3.1-1 and 3.3.1-2, addresses how steel cranes structural girders exposed to air-indoor uncontrolled (external), and steel and stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air-indoor uncontrolled, treated borated water or treated water are being managed for cumulative fatigue damage. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3, and is required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that TLAAs identified for fatigue in the chemical and volume control system (CVCS) are discussed in LRA Section 4.3, and the evaluation of crane load cycles as a TLAA for cranes is discussed in LRA Section 4.7.6.

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 these auxiliary system components is a TLAA, as defined in 10 CFR 54.3. 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 SRP-LR Section 4.3, "Metal Fatigue Analysis," or SRP-LR Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses." The staff reviewed the applicant's AMR items and finds that the AMR results are consistent with the recommendations of the GALL Report and SRP-LR for managing cumulative fatigue damage in steel cranes, structural girders exposed to air-indoor uncontrolled (external), and steel and stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air-indoor uncontrolled, treated borated water or treated water, except as identified below.

In its review of LRA Table 3.3.2-3, the staff noted that, in addition to the AMR items associated with item 3.3.1-2, the applicant also included two AMR items associated with item 3.1.1-8 regarding TLAAs of valve body (Class 1) and piping and fittings (Class 1 less than 4 in.). LRA Section 4.3.7 states that the CVCS components were designed in accordance with ASME Code Section III Class 2 and Class 3 requirements. It is not clear to the staff which piping and fittings are represented in LRA Table 3.3.2-3 and whether the two AMR items (3.1.1-8) represent the portion of the CVCS that is located inside the reactor containment. By letter dated January 21, 2010, the staff issued RAI 3.3.2.2.1-2 asking the applicant to clarify which portions of the CVCS system are represented by AMR items 3.1.1-8 in LRA Table 3.3.2-3 for the CVCS. The staff also asked the applicant to clarify the inconsistency between LRA Section 4.3.7, which stated that the CVCS components were designed to ASME Code Section III Class 2 and Class 3 requirements, and LRA Table 3.1.1, item 3.1.1-8, which represents Class 1 components. Furthermore, the staff requested that the applicant identify the TLAA in LRA Section 4 that represents the fatigue analysis for these Class 1 components.

In its response dated February 18, 2011, the applicant clarified that item 3.1.1-8 represents the Class 1 RCPB components in the CVCS (LRA Table 3.3.2-3) system. The applicant also stated that item 3.3.1-2, which represents the Class 2 and Class 3 components in the CVCS, were already included in LRA Table 3.3.2-3, and no changes were necessary. The applicant stated that the Class 1 RCPB components in the CVCS are part of the NSSS and are evaluated in LRA Sections 4.3.1 and 4.3.2. The applicant also stated that the TLAAs for Class 2 and Class 3 components are evaluated in LRA Section 4.3.7.

Based on its review, the staff finds the applicant's response to RAI 3.3.2.2.1-2 acceptable because the applicant clarified the AMR items and associated TLAAs for Class 1 RCPB components and Class 2 and Class 3 components in the CVCS, and the applicant's AMR results are consistent with the recommendations of the GALL Report. The staff's review of the applicant's TLAAs associated with the Class 1 components and Class 2 and Class 3 components are documented in SER Section 4.3. The staff's concern described in RAI 3.3.2.2.1-2 is resolved.

The staff noted that LRA Table 3.5.2-3 does not include any applicable items for management of cumulative fatigue damage in the steel cranes structural girders even though LRA Section 4.7.6 discusses the TLAA associated with crane load cycle limits. By letter dated

January 21, 2010, the staff issued RAI 3.3.2.2.1-1, Request 2, asking the applicant to include in LRA Table 3.5.2-3 the applicable items for management of cumulative fatigue damage in the steel cranes structural girders or provide the basis for excluding these items from the LRA.

In its response dated February 18, 2011, the applicant amended LRA Table 3.5.2-3 to include the associated AMR items for the steel crane structural girders for fuel handling and overhead cranes, consistent with GALL Report AMR item VII.B-2. The applicant stated that two rows representing TLAAs of steel structural support for 1-FH-RE-1 spent fuel cask handling crane and 1-MM-CR-3 polar gantry crane exposed to air-indoor uncontrolled have been added to LRA Table 3.5.2-3.

Based on its review of the amended LRA Table 3.5.2-3, the staff finds the applicant's response to RAI 3.3.2.2.1-1, Request 2, and the additions of the AMR items acceptable because they are consistent with GALL AMR item VII.B-2 for the steel cranes structural girders. The staff's concern described in RAI 3.3.2.2.1-1, Request 2, is resolved.

Based on the staff's review, it concludes that the applicant met the SRP-LR Section 3.3.2.2.1 criteria. For those items that apply to LRA Section 3.3.2.2.1, the staff determined that the LRA is consistent with the GALL Report and that the applicant 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). SER Sections 4.3 and 4.7 document the staff's review of the applicant's evaluation of the TLAAs for these components.

3.3.2.2.2 Reduction of Heat Transfer due to Fouling

LRA Section 3.3.2.2.2 is associated with LRA Table 3.3.1, item 3.3.1-3, and addresses stainless steel heat exchanger tubes exposed to treated water. The applicant stated that this item is not applicable because this item is associated with the GALL item VII.E3-6, which applies to BWR reactor water cleanup system heat exchangers. The staff noted that the related item, AP-62, from SRP-LR Table 3.3.1, was derived from a previous SER for heat exchanger tubes exposed to treated borated water in a spent fuel pool system. Based on this, the applicant's determination that this item was not applicable did not appear appropriate. By letter dated February 24, 2011, the staff issued RAI 3.3.2.2.2-1 requesting that the applicant provide additional bases regarding the non-applicability of this item and the bases for not managing reduction of heat transfer for heat exchanger tubes identified as having a heat transfer function.

In its response dated March 22, 2011, the applicant stated that the "treated borated water" environment is different from the "treated water" environment. The applicant provided the definitions of treated water and treated boated water from the GALL Report Section IX.D, which states that, unlike the PWR reactor coolant environment (treated borated water), the BWR reactor coolant environment (treated water) does not contain boron, a recognized corrosion inhibitor. The applicant also referred to GALL Report Section IX.F, which describes fouling as an accumulation of deposits that may be due to particulate fouling, such as sediment, silt or corrosion products. The applicant further stated that none of the heat exchanger tubes in LRA Section 3.3 are exposed to treated water; however, there are stainless steel heat exchanger tubes exposed to treated borated water in the auxiliary systems. The applicant provided the following basis for its determination that these components are not susceptible to reduction of heat transfer:

Seabrook's determination that reduction of heat transfer is not an aging effect in treated borated water environment is based on plant and industry operating experience. Seabrook is not aware of any fouling in treated borated water environment leading to reduction of heat transfer in stainless steel heat exchanger tubes. This conclusion is consistent with NUREG-1801, Revision 1. NUREG-1801, Revision 1, does not identify reduction of heat transfer as an aging effect for stainless steel heat exchanger tubes in treated borated water environment.

Fouling of the stainless steel heat exchanger tubes on the treated borated water side would only occur through the buildup of corrosion products. Since Seabrook's treated borated water contains boron, a corrosion inhibitor, corrosion product buildup resulting in reduction of heat transfer in treated borated water environment is not a credible aging effect/mechanism. This is further validated by NUREG-1801, Revision 1, items V.A-27 and V.D1-30 (NUREG-1800, Table 3.2-1, items 48 and 49), which state that Water Chemistry Program alone (for PWR primary water) is adequate for managing loss of material in stainless steel components exposed to treated borated water, indicating that corrosion is not expected to occur in stainless steel components exposed to treated borated water. In the absence of corrosion, corrosion product buildup will not occur.

The applicant also stated that since reduction of heat transfer in treated borated water is not identified as a potential aging effect, no items for reduction of heat transfer in treated borated water appear in the LRA. The applicant further stated that its conclusion is consistent with NUREG-1810, Revision 1 and Revision 2, as well as the staff conclusions, as stated in the Beaver Valley (Section 3.2.2.3.2) and Prairie Island (Section 3.2.2.2.4) final SERs.

The staff reviewed the applicant response and the cited portions of the GALL Report. The staff noted that, although the GALL Report, Revision 1, states that boron is a recognized corrosion inhibitor, the GALL Report, Revision 2, deleted that discussion from the definition of treated water. The staff also reviewed the AMR items V.A-27 and V.D1-30 (SRP-LR, Table 3.2, item 49) and noted that the GALL Report credits water chemistry to manage loss of material due to pitting and crevice corrosion in stainless components exposed to treated borated water. The staff noted that, although the basis for adding these items in the GALL Report, Revision 1, stated that a significant loss of material was not expected, the potential for corrosion and consequently corrosion product buildup still exists. The staff also reviewed the Beaver Valley and Prairie Island SERs, and the associated LRAs cited by the applicant, and noted that both LRAs identified reduction of heat transfer for stainless steel heat exchanger tubes in a treated borated water environment as an aging effect requiring managing. Based on the above, by letter dated May 23, 2011, the staff issued RAI 3.2.2.2.4.2-1A, requesting that the applicant justify why heat exchanger tubes, which have a heat transfer intended function, do not need to include a reduction of heat transfer aging effect requiring management. In addition, the RAI asked the applicant to provide the plant-specific and industry operating experience cited in its response demonstrating that reduction in heat transfer was not a credible aging effect for the components in question.

In its response dated June 2, 2011, the applicant revised LRA Tables 3.3.2-3 and 3.3.2-39 to include AMR items for stainless steel heat exchanger components in treated borated water environment that are being managed for reduction of heat transfer by the Water Chemistry Program. The AMR items cite generic note H and plant-specific notes, which state that reduction of heat transfer due to fouling is not in the GALL Report for this component, material, and environment combination.

The staff finds the applicant's response unacceptable because the guidance in the SRP-LR and GALL Report was revised in LR-ISG-2011-01, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water," to add the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage stainless steel components for loss of material, cracking, and reduction of heat transfer in treated borated water environments that are not controlled to low oxygen levels. The staff noted that, prior to the issuance of LR-ISG-2011-01, the SRP-LR and GALL Report guidance inappropriately credited the boron in borated water as a corrosion inhibitor in place of other aging management activities.

By letter dated May 29, 2012, the staff issued RAI 3.2.1.48-1 requesting that the applicant describe how the effectiveness of the Water Chemistry Program to manage reduction of heat transfer will be verified for stainless steel components exposed to treated borated water with greater than 5 ppb oxygen. Pending the staff's review of the applicant's response, this issue is identified as Open Item OI 3.2.2.1-1.

3.3.2.2.3 Cracking due to Stress Corrosion Cracking

The staff reviewed LRA Section 3.3.2.2.3 against the following criteria in SRP-LR Section 3.3.2.2.3:

(1) SRP-LR Section 3.3.2.2.3 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 140 °F (60 °C).

LRA Section 3.3.2.2.3.1, associated with LRA Table 3.3.1, item 3.3.1-4, addresses cracking due to SCC in stainless steel piping, piping components, and piping elements exposed to sodium pentaborate at greater than 140 °F (60 °C). The applicant stated that this item is not applicable because this aging issue is only applicable to BWRs. The staff reviewed SRP-LR and confirmed that this aging effect is only applicable to the standby liquid control system, which is only associated with BWRs; therefore, it finds the applicant's determination acceptable.

(2) LRA Section 3.3.2.2.3.2, is associated with LRA Table 3.3.1, item 3.3.1-5, and addresses stainless steel and stainless clad steel heat exchanger components exposed to treated water greater than 140 °F (60 °C). The applicant stated that this item is not applicable because this item is associated with GALL items VII.E3-3 and VII.E3-19, which apply to BWR reactor water cleanup system heat exchangers. The staff reviewed LRA Section 3.3 and noted that, although there were no in-scope stainless steel heat exchanger tubes exposed to treated water greater than 140 °F (60 °C) present in the auxiliary systems, there were several systems with heat exchanger tubes exposed to treated borated water greater than 140 °F (60 °C). As a result, the staff considered this aging effect to be applicable to these components. However, the staff also noted that the applicant aligned these components with item 3.3.1-7, which is associated with non-regenerative heat exchanger tubes and cited generic note E indicating that a different AMP or plant-specific AMP was credited to manage this aging effect. The staff further noted that the applicant also cited plant-specific note 7 for these components, which stated that the Water Chemistry and One-Time Inspection Programs were used to manage this aging effect. The staff finds the applicant's determination, that item 3.3.1-5 is not applicable, acceptable because the applicant aligned the applicable components with item 3.3.1-7, which has comparable acceptance criteria as item 3.3.1-5; consequently, it will adequately manage this aging effect.

(3) LRA Section 3.3.2.2.3.3 is associated with LRA Table 3.3.1, item 3.3.1-6, and addresses stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust, which are being managed for cracking due to SCC by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The criteria in SRP-LR Section 3.3.2.2.3, item 3, state that cracking due to SCC could occur for stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The SRP-LR states that a plant-specific AMP should be used. The SRP-LR also states that acceptance criteria for the plant-specific AMP will include a description of its basis and analysis methodology, ensure continued functional operation of structure and components, contain quantified criteria or a illustrate method of quantification, and discuss qualitative inspections via ASME or site-specific criteria. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage cracking due to SCC for the stainless steel diesel exhaust piping components exposed to diesel exhaust in the diesel generator system and fire protection system.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff noted that the AMP includes visual surface, magnification, and ultrasonic inspection methods. The staff also noted that the reports will be evaluated by a system engineer who will help ensure the extent and schedule of inspections to detect degradation prior to loss of function, and these reviews will include trending to determine whether the number of locations and intervals are providing aging management consistent with the CLB. Acceptance criteria for various corrosion mechanisms will be identified in appropriate inspection procedures. The staff further noted that GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," states that inspections are performed when the internal surfaces are accessible during the performance of periodic surveillances and during maintenance activities or during scheduled outages. It also states that inspection intervals are established such that they provide timely detection of degradation. In its review of components associated with LRA Table 3.3.1, item 3.3.1-6, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable for the following reasons:

- The applicant will perform sufficient inspections for each material-environment combination to provide an overall assessment of any aging degradation that may be occurring.
- 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.
- Recurring surveillance and maintenance activities provides the ability to detect aging of the material-environment combination prior to loss of function.
- Inspection results will be trended.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.3, item 3, criteria. For those items that apply to LRA

Section 3.3.2.2.3.3, the staff determined that the LRA is consistent with the GALL Report and that the applicant 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 following criteria in SRP-LR Section 3.3.2.2.4:

(1) LRA Section 3.3.2.2.4.1, is associated with LRA Table 3.3.1, item 3.3.1-7, and addresses cracking due to SCC and cyclic loading in stainless steel non-regenerative heat exchanger components exposed to treated borated water greater than 140 °F (60 °C), which are being managed by the Water Chemistry and the One-Time Inspection Programs. The criteria in SRP-LR Section 3.3.2.2.4, item 1, states that the existing AMP monitors and controls primary water chemistry to manage cracking due to SCC; however, control of water chemistry does not preclude cracking due to SCC and cyclic loading. The SRP-LR also states that the effectiveness of Water Chemistry Control Programs should be confirmed using a plant-specific AMP, and an acceptable verification program includes temperature and radioactivity monitoring of the shell side water and eddy current testing of the tubes. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry Program will manage this aging effect, and the effectiveness of the program will be confirmed by the One-Time Inspection Program.

The staff's evaluations of the applicant's Water Chemistry and the One-Time Inspection Programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. The staff reviewed the applicant's Water Chemistry Program and noted that it controls detrimental contaminants below the levels known to cause cracking. The staff also noted that the applicant credited its One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage this aging effect. However, it is not clear whether the non-regenerative heat exchangers will be included in the sample of components to be inspected and what inspection techniques will be used. In addition, it is also not clear if temperature and radioactivity monitoring of the shell side water is performed to verify the integrity of the heat exchangers. By letter dated January 5, 2011, the staff issued RAI 3.3.2.2.4-1 requesting that the applicant clarify if the non-regenerative heat exchangers will be included in sample of components to be inspected, to provide the inspection method that will be used to detect cracking in the heat exchanger tubes, and to confirm if temperature and radioactivity monitoring of the shell side water is performed.

In its response dated February 3, 2011, the applicant stated that the non-regenerative heat exchangers will be included in the sample of components to be inspected in the One-Time Inspection Program and that eddy current testing will be used to detect cracking in the stainless steel tubes. The applicant also revised LRA Section 3.3.2.2.4.1, item 1, and stated that temperature and radioactivity monitoring of the shell side water is performed to verify the integrity of the heat exchangers.

The staff finds the applicant response acceptable because the applicant is consistent with the GALL Report recommendation of verification program of eddy current testing of tubes to detect cracking and temperature and radioactivity monitoring of the shell side water to verify heat exchanger integrity. The staff's concern described in RAI 3.3.2.2.4-1 is resolved.

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 items that apply to LRA Section 3.2.2.2.4.1, the staff determined that the LRA is consistent with the GALL Report. The staff also determined that the applicant 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 3.3.2.2.4.2, is associated with LRA Table 3.3.1, item 3.3.1-8, and addresses cracking due to SCC and cyclic loading in stainless steel regenerative heat exchanger components exposed to treated borated water greater than 140 °F (60 °C). The criteria in SRP-LR Section 3.3.2.2.4, item 2, states that cracking due to SCC and cyclic loading may occur in stainless steel regenerative heat exchanger components exposed to treated borated water greater than 140 °F (60 °C). The SRP-LR also states that the existing AMP monitors and controls primary water chemistry to manage cracking due to SCC; however, these controls do not preclude cracking and recommend that the effectiveness of Water Chemistry Control Program be confirmed using a plant-specific AMP. The applicant addressed the further evaluation criteria of the SRP-LR by stating that this aging effect will be managed by the Water Chemistry Program. The applicant also stated that, since the regenerative heat exchanger is welded and cannot be disassembled for internal inspection, the effectiveness of the water chemistry controls will be confirmed by a one-time inspection of a non-regenerative heat exchanger with the same material and environment combination in the chemical and volume control system. The applicant further stated that the integrity of the regenerative heat exchanger is confirmed by continuous temperature monitoring.

SRP-LR Section 3.3.2.2.4 states that cracking due to SCC and cyclic loading may occur in stainless steel PWR regenerative heat exchanger components exposed to treated borated water greater than 140 °F (60 °C). The existing AMP monitors and controls primary water chemistry in PWRs to manage the aging effects of cracking due to SCC. However, control of water chemistry does not preclude cracking due to SCC and cyclic loading; therefore, the effectiveness of Water Chemistry Control Programs should be confirmed to ensure that cracking does not occur. The GALL Report recommends that a plant-specific AMP be evaluated to verify the absence of cracking due to SCC and cyclic loading to ensure that these aging effects are adequately managed.

The staff's evaluations of the applicant's Water Chemistry and the One-Time Inspection Programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. In its review of components associated with item 3.3.1-8, the staff finds that the applicant met the further evaluation criteria. The staff also found that the applicant's proposal to manage aging using the specified programs is acceptable because the Water Chemistry Program includes control of detrimental contaminants below the levels known to cause cracking. Additionally, the one-time inspection of the non-regenerative heat exchanger will verify the effectiveness of the Water Chemistry Program and confirm that cracking in not occurring in comparable components in the same environment.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.4, item 2, criteria. For those items that apply to LRA

Section 3.2.2.2.4.2, the staff determined that the LRA is consistent with the GALL Report. The staff also determined that the applicant 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 3.3.2.2.4.3, associated with LRA Table 3.3.1, item 3.3.1-9, addresses stainless steel high-pressure pump casings, exposed to treated borated water in the chemical and volume control system, which are being managed for cracking due to SCC and cyclic loading by the Water Chemistry Program and the One-Time Inspection Program. The criteria in SRP-LR Section 3.3.2.2.4, item 3, states that cracking due to SCC and cyclic loading could occur for stainless steel pump casings for the PWR high-pressure pumps in the chemical and volume control system. The SRP-LR also states that the GALL Report recommends the existing AMP, including monitoring and control of primary water chemistry. The SRP-LR further recommends that this aging issue be managed by a plant-specific program to verify the effectiveness of the Water Chemistry Control Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry Program effectiveness will be confirmed by the One-Time Inspection Program.

The staff's evaluations of the applicant's Water Chemistry Program and the One-Time Inspection Program are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. In its review of components associated with item 3.3.1-9, the staff finds that the applicant met the further evaluation criteria, and the applicant's proposal to manage aging using the Water Chemistry Program and the One-Time Inspection Program is acceptable because the Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate the environmental effect that can cause cracking and takes actions if the parameters exceed the limits. Additionally, the One-Time Inspection Program is adequate to confirm the effectiveness of the Water Chemistry Program.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.4, item 3, criteria. For those items that apply to LRA Section 3.3.2.2.4.3, the staff determined that the LRA is consistent with the GALL Report and that the applicant 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 3.3.2.2.4.4, associated with LRA Table 3.3.1, item 3.3.1-10, addresses cracking due to SCC and cyclic loading in high-strength steel closure bolting exposed to air with steam or water leakage. The applicant stated that this item is not applicable because there is no high-strength steel closure bolting exposed to air with steam or water leakage in the auxiliary system. The staff reviewed LRA Sections 2.3.3 and 3.3 and the UFSAR and confirmed that no in-scope high-strength steel closure bolting exposed to air with steam or water leakage are present in the auxiliary system; therefore, it finds the applicant's claim acceptable.

3.3.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

The staff reviewed LRA Section 3.3.2.2.5 against the following criteria in SRP-LR Section 3.3.2.2.5:

(1) LRA Section 3.3.2.2.5.1, is associated with LRA Table 3.3.1, item 3.3.1-11, and addresses elastomer seals and components exposed to air-indoor uncontrolled, internal or external environments, which are being managed for hardening and loss of strength due to elastomer degradation by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for internal surfaces and the External Surfaces Monitoring Program for external surfaces. The criteria in SRP-LR Section 3.3.2.2.5, item 1, state that hardening and loss of strength due to elastomer degradation may occur in elastomeric seals and components associated with auxiliary heating and ventilation systems that are exposed either internally or externally to uncontrolled indoor air. The SRP-LR recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is adequate to manage the aging effects on the internal surfaces of these components, and the External Surfaces Monitoring Program is adequate to manage the aging effects on the external surfaces of these components.

SRP-LR Section 3.3.2.2.5 states that hardening and loss of strength due to elastomer degradation may occur in elastomer seals and components of heating and ventilation systems exposed to air-indoor uncontrolled (internal or external). The GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program provides for inspections of opportunity, performed during pre-planned, periodic system and component surveillances, or during maintenance activities when the systems are opened and the surfaces are made accessible for visual inspection. The staff also noted that for elastomeric materials, the program uses tactile techniques, which include scratching, bending, folding, stretching, and pressing in conjunction with the visual examinations.

The staff's evaluation of the applicant's Inspection of External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff noted that the External Surfaces Monitoring Program uses periodic system inspections and walkdowns to monitor for materials degradation and leakage. The staff also noted that for elastomeric materials, the program uses tactile techniques, which include scratching, bending, folding, stretching, and pressing in conjunction with the visual examinations.

In its review of components associated with LRA Table 3.3.1, item 3.3.1-11, the staff finds that the applicant met the further evaluation criteria. The staff also finds that the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and the External Surfaces Monitoring Program is acceptable because the programs use a methodology that is capable of detecting hardening and loss of strength caused by elastomer degradation before loss of intended function occurs.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.5, item 1, criteria. For those items that apply to LRA Section 3.2.2.2.5.1, the staff determined that the LRA is consistent with the GALL

Report. The staff also determined that the applicant 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, is associated with LRA Table 3.3.1, item 3.3.1-12, and addresses elastomer lined components exposed to treated borated water in the chemical and volume control system, which are being managed for hardening and loss of strength due to elastomer degradation by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

The criteria in SRP-LR Section 3.3.2.2.5, item 2, state that hardening and loss of strength due to elastomer degradation may 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 SRP-LR also states that the GALL Report recommends that a plant-specific AMP be evaluated that determines and assesses the qualified life of the elastomeric liners in the environment to ensure that these aging effects are adequately managed. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is adequate to manage the aging effects of these components.

The applicant is using LRA Table 3.3.1, item 3.3.1-12, to address elastomer flex hoses exposed to treated borated water. The staff noted that elastomer flex hoses, when exposed to treated borated water, will have the same aging effect of hardening and loss of strength as elastomer-lined components in the same environment. The applicant stated that for item 3.3.1-12, the applicability is limited to the chemical and volume control system. The staff also noted that a search of the applicant's UFSAR for the spent fuel pool cooling and cleanup and chemical volume control systems confirmed that no in-scope elastomer-lined components exposed to treated borated water are present in the spent fuel pool cooling and cleanup system.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program provides for inspections of opportunity, performed during pre-planned, periodic system and component surveillances, or during maintenance activities when the systems are opened and the surfaces are made accessible for visual inspection. The staff also noted that for elastomeric materials, the program uses tactile techniques, which include scratching, bending, folding, stretching, and pressing in conjunction with the visual examinations.

In its review of components associated with LRA Table 3.3.1, item 3.3.1-12, the staff finds that the applicant met the further evaluation criteria. Additionally, the staff finds that the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable because the program uses a methodology that is capable of detecting hardening and loss of strength caused by elastomer degradation before loss of intended function occurs.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.5, item 2, criteria. For those items that apply to LRA Section 3.2.2.2.5.2, the staff determined that the LRA is consistent with the GALL

Report. The staff also determined that the applicant 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, referenced by LRA Table 3.3.1, item 3.3.1-13, addresses Boral, boron steel spent fuel storage racks neutron-absorbing sheets exposed to treated water or treated borated water, which are being managed for reduction of neutron–absorbing capacity and loss of material due to general corrosion. The applicant addressed the further evaluation criteria by stating that the Boral Monitoring Program, B.2.2.2, will be used to manage reduction of the neutron-absorbing capacity and loss of material due to general corrosion of the Boral poison sheet in the spent fuel pool, in treated water exposed to treated borated water.

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 in the neutron-absorbing sheets of BWR and PWR spent fuel storage racks exposed to treated water or to 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 and that acceptance criteria are described in BTP RLSB-1.

The staff evaluated the applicant’s Boral Monitoring Program, as documented in SER Section 3.0.3.3.3. 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 acceptable because the Boral Monitoring Program satisfies the acceptance criteria of the SRP-LR and uses inspection techniques (e.g., boron areal density measurement, and visual inspections) that will detect aging effects related to the neutron absorption and dimensional integrity.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

Based on the programs identified above, the staff concludes that the applicant’s programs meet SRP-LR Section 3.3.2.2.6 criteria. For those items that apply to LRA Section 3.3.2.2.6, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 following criteria in SRP-LR Section 3.3.2.2.7:

(1) LRA Section 3.3.2.2.7.1, referenced by LRA Table 3.3.1, item 3.3.1-14, addresses steel piping, piping components, and piping elements exposed to lubricating oil, which are being managed by the Lubricating Oil Analysis 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 used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material due to general, pitting, and crevice corrosion through examination of susceptible locations in steel tanks in the chemical and volume control, diesel generator, instrument air, and miscellaneous equipment systems. The applicant further stated that the Lubricating Oil Analysis Program and the One-Time Inspection Program will also be used to manage loss of material due to general, pitting, and crevice corrosion through examination of susceptible locations in steel piping components in the chemical and volume control system, diesel generator, fire protection, instrument air, miscellaneous equipment, and service water systems. Finally, the applicant stated that the Lubricating Oil Analysis Program and the One-Time Inspection Program will be used to manage loss of material due to general, pitting, and crevice corrosion through examination of susceptible locations in galvanized steel piping components in the service water system.

LRA Section 3.3.2.2.7.1, referenced by LRA Table 3.3.1, item 3.3.1-15, addresses steel reactor coolant pump oil collection system tank exposed to lubricating oil, 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 criteria of the SRP-LR by stating that this item was not applicable because Seabrook does not have steel containment isolation piping, piping components, crevice corrosion evaluated components, and piping elements internal surfaces exposed to lubricating oil in the oil collection for reactor coolant pumps system.

LRA Section 3.3.2.2.7.1, referenced by LRA Table 3.3.1, item 3.3.1-16, addresses steel reactor coolant pump oil collection system and chemical and volume control system tanks exposed to lubricating oil, 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 criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage for loss of material due to general, pitting, and crevice corrosion by the Lubricating Oil Analysis and One-Time Inspection Programs. Additionally, the applicant stated that the Lubricating Oil Analysis and One-Time Inspection Programs will manage loss of material due to general, pitting, and crevice corrosion by including a one-time thickness measurement on the bottom portion of the steel tanks exposed to lubricating oil in the oil collection for the reactor coolant pumps system.

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 in 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 stated that the existing AMP 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. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil control should be confirmed to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the Lubricating Oil Analysis Program for which a one-time inspection of selected 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.

In addition, the SRP-LR states that corrosion may occur at locations in the reactor coolant pump oil collection tank where water from wash downs may accumulate; therefore, the effectiveness of the program should be confirmed to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion. This includes determining the thickness of the lower portion of the tank for which a one-time inspection 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 Table 3.3.2-25, "Oil Collection for Reactor Coolant Pump System, Summary of Aging Management Evaluation," of the applicants LRA and the UFSAR to verify that there is no steel reactor coolant pump oil collection system piping components exposed to lubricating oil in the oil collection for reactor coolant pumps system. Based on the information provided in Table 3.3.2-25, the staff confirmed that the oil collection for reactor coolant pumps system only has stainless steel piping components exposed to lubricating oil. Therefore, the staff finds that item 3.3.1-15 is not applicable.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. In its review of components associated with items 3.3.1-14 and 3.3.1-16, the staff finds the applicant's proposal to manage the applicable aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable. The Lubricating Oil Analysis Program was determined to be consistent with the GALL Report, and the applicant stated that the One-Time Inspection Program will be used to examine steel piping and piping components to verify the effectiveness of the Lubricating Oil Analysis Program.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.7, item 1 criteria. For those items that apply to LRA Section 3.3.2.2.7.1, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 3.3.2.2.7.2, associated with LRA Table 3.3.1, item 3.3.1-17, addresses loss of material due to general, pitting, and crevice corrosion in BWR steel piping, piping components, and piping elements exposed to treated water. The applicant stated that this item is not applicable because it is only applicable to BWRs. The staff reviewed the SRP-LR and LRA Section 3.3 and noted that this item is associated only with BWRs; therefore, if finds the applicant's claim acceptable.

(3) LRA Section 3.3.2.2.7.3 is associated with LRA Table 3.3.1, item 3.3.1-18, and addresses stainless steel and steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust, which are being managed for loss of material due to general (steel only), pitting, and crevice corrosion by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components. The criteria in SRP-LR Section 3.3.2.2.7, item 3, state that loss of material due to general (steel only), pitting, and crevice corrosion could occur for steel and stainless steel diesel exhaust

piping, piping components, and piping elements exposed to diesel exhaust. The SRP-LR states that a plant-specific AMP should be used. The SRP-LR also states that acceptance criteria for a plant-specific AMP will include a description of its basis and analysis methodology, ensure continued functional operation of structure and components, contain quantified criteria or a illustrate method of quantification, and discuss qualitative inspections via ASME or site-specific criteria. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage loss of material due to general (steel only), pitting, and crevice corrosion of the steel piping components, steel silencer (diesel generator system), and stainless steel piping components exposed to diesel exhaust in the diesel generator system and fire protection system.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff noted that the AMP includes visual surface, magnification, and ultrasonic inspection methods. The staff also noted that reports will be evaluated by a system engineer who will help ensure the extent and schedule of inspections to detect degradation prior to loss of function, and these reviews will include trending to determine whether the number of locations and intervals are providing aging management consistent with the CLB. Acceptance criteria for various corrosion mechanisms will be identified in appropriate inspection procedures. In its review of components associated with LRA Table 3.3.1, item 3.3.1-18, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable for the following reasons:

- The applicant will perform sufficient inspections for each material-environment combination to provide an overall assessment of any aging degradation that may be occurring.
- 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.
- Recurring surveillance and maintenance activities provides the ability to detect aging of the material prior to loss of function.
- Inspection results will be trended.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.7, item 3 criteria. For those items that apply to LRA Section 3.3.2.2.7.3, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 LRA Table 3.3.1, item 3.3.1-19, and addresses steel piping, piping components and piping elements exposed to soil, which are being managed for loss of material due to general, pitting, crevice, and MIC by the Buried Piping and Tanks Inspection Program. The criteria in SRP-LR Section 3.3.2.2.8, state that the loss of material due to general, pitting, crevice, and MIC could occur for steel (with or without coating or wrapping) piping, piping components, and piping elements exposed to soil environment. The SRP-LR also states that the Buried Piping and Tanks Inspection Program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material aging effect. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Buried Piping and Tanks Inspection Program will use external coatings and wrappings installed to industry standards on buried piping as well as periodic inspections to determine loss of material. The staff noted that the applicant stated, in LRA Section B.2.1-22, under the “detection of aging effects” program element that inspections locations would be, in part, based on areas with a history of corrosion problems.

SRP-LR Section 3.3.2.2.8 states that loss of material due to general, pitting, and crevice corrosion and MIC may occur in steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. Buried Piping and Tanks Inspection Programs rely on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general, pitting, and crevice corrosion and MIC. The effectiveness of the Buried Piping and Tanks Inspection Program should be confirmed to evaluate an applicant’s inspection frequency and operating experience with buried components, ensuring that loss of material does not occur.

The staff’s evaluation of the applicant’s Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.3.1. The applicant stated that the Buried Piping and Tanks Inspection Program will manage loss of material due to general, pitting, crevice, and MIC by employing preventive measures such as external coatings and wrappings and performing periodic inspections to detect aging effects. The applicant further stated that, during installation, steel and stainless steel buried piping contained either external coatings or wrappings to mitigate corrosion. The applicant stated that visual inspections will be performed on the protective wraps and coatings to look for evidence of damaged wrapping or coating defects. The applicant stated that if defects are found then the external surface of the pipe will be further inspected for loss of material. The applicant also stated that ultrasonic inspections or other advanced inspection methods may be used to detect for loss of material. Additionally, visual inspections will be performed at least once during the 10-year period of extended operation or when pipes are excavated for maintenance or other activities. In its review of components associated with item 3.3.1-19, the staff finds that the applicant has met the further evaluation criteria, and the applicant’s proposal to manage aging using the Buried Piping and Tanks Inspection Program is acceptable for the following reasons:

- The program includes preventive actions, such as external coatings and wrappings installed to industry standard practices and backfill that will not damage the piping or coatings, and some systems are protected by a cathodic protection system.
- Periodic visual inspections will be performed starting 10 years prior to the period of extended operation and extend into both 10-year periods during the period of extended operation to ensure that coatings remain intact or uncoated piping has not degraded.
- Plant-specific operating experience will be used to inform inspection locations.

- Alternatives to direct visual inspection, such as pressure tests or ultrasonic inspections, are capable of detecting piping degradation.

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 determined that the LRA is consistent with the GALL Report, and the applicant 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).

3.3.2.2.9 Loss of Material Due to General, Pitting, Crevice, Microbiologically-Influenced Corrosion, and Fouling

The staff reviewed LRA Section 3.3.2.2.9 against the following criteria in SRP-LR Section 3.3.2.2.9:

(1) LRA Section 3.3.2.2.9.1, referenced by LRA Table 3.3.1, item 3.3.1-20, addresses steel piping, piping components, piping elements, and tanks exposed to fuel oil, which are being managed for loss of material due to general, pitting, crevice, MIC, and fouling by the Fuel Oil Chemistry Program and One-Time Inspection Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Fuel Oil Chemistry Program to manage the loss of material through examination of susceptible locations in steel piping, piping components, piping elements, and tanks exposed to fuel oil in the fuel oil system.

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 loss of material due to general, pitting, crevice, MIC, and fouling could occur for steel piping, piping components, piping elements, and tanks exposed to fuel oil. The SRP-LR also stated 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 confirmed to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, crevice, MIC, and fouling to verify the effectiveness of the Fuel Oil Chemistry Program. It also states that a one-time inspection of selected 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's evaluations of the applicant's Fuel Oil Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.10 and 3.0.3.1.8, respectively. In its review of components associated with item 3.3.1-20, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Fuel Oil Chemistry Program acceptable because the Fuel Oil Chemistry Program was determined to be consistent with the GALL Report. Additionally, the applicant stated that the One-Time Inspection Program will be used to examine steel piping, piping components, piping elements to verify the effectiveness of the Fuel Oil Chemistry Program. This satisfies the acceptance criteria in SRP-LR Section 3.3.2.2.9, item 1; therefore, the applicant's AMR is consistent with GALL Report.

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 the items that apply to LRA Section 3.3.2.2.9.1, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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, referenced by LRA Table 3.3.1, item 3.3.1-21, addresses steel heat exchanger components exposed to lubricating oil, which are being managed for loss of material due to general, pitting, crevice, MIC, and fouling by the Lubricating Oil Analysis and One-Time Inspection Programs. SRP-LR Section 3.3.2.2.9, item 2, states that loss of material due to general, pitting, and crevice corrosion, MIC, and fouling may occur in steel heat exchanger components exposed to lubricating oil. The existing AMP periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be fully effective in precluding corrosion; therefore, the effectiveness of lubricating oil control should be confirmed to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of lubricating oil programs. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that component-intended functions will be maintained during the period of extended operation.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. In its review of components associated with item 3.3.1-21, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report. Additionally, the applicant stated that the One-Time Inspection Program will be used to examine steel heat exchanger components to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.3.2.2.9, item 2; therefore, the applicant's AMR is consistent with the GALL Report.

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 the items that apply to LRA Section 3.3.2.2.9.2, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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

(1) LRA Section 3.3.2.2.10.1, associated with LRA Table 3.3.1, item 3.3.1-22, addresses loss of material due to pitting and crevice corrosion in steel piping with elastomer lining or stainless steel cladding exposed to treated water or treated borated water if the cladding or lining is degraded. The applicant stated that this item is not applicable because there are no steel with elastomer lining components exposed to treated borated water in the spent fuel pool cooing system, and GALL Report item VII.A4-12 is only applicable to BWR plants.

The staff reviewed LRA Sections 2.3.3 and 3.3 and the UFSAR and confirmed that no in-scope steel piping with elastomer lining exposed to treated borated water is present in the spent fuel pool cooing system. The staff confirmed that GALL Report item VII.A4-12, steel with elastomer lining or stainless steel cladding, is only applicable to BWR plants; therefore, it finds the applicant's claim acceptable.

(2) LRA Section 3.3.2.2.10.2, associated with LRA Table 3.3.1, items 3.3.1-23 and 3.3.1-24, addresses loss of material due to pitting and crevice corrosion in stainless steel and steel with stainless steel cladding heat exchanger components, and stainless steel and aluminum piping, piping components, and piping elements exposed to treated water. The applicant stated that these items are not applicable because they are only applicable to BWRs.

SRP-LR Section 3.3.2.2.10 states that loss of material due to pitting and crevice corrosion may occur in stainless steel and aluminum piping, piping components, piping elements, and for stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water. The existing AMP monitors and controls reactor water chemistry to manage the aging effects of loss of material from pitting and crevice corrosion. However, high concentrations of impurities in crevices and with stagnant flow conditions may cause pitting or crevice corrosion; therefore, the effectiveness of Water Chemistry Control Programs should be confirmed to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage loss of material from pitting and crevice corrosion to verify the effectiveness of Water Chemistry Control Programs. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that component-intended functions will be maintained during the period of extended operation.

The staff noted that SRP-LR items 3.3.1-23 and 3.3.1-24 are associated with GALL items VII.A4-2, VII.A4-5, VII.A4-11, VII.E3-7, VII.E3-15, VII.E4-4, and VII.E4-14, all of which are associated with BWR spent fuel pool cooling and cleanup, reactor water cleanup, and shutdown cooling systems; therefore, it finds the applicant's claim acceptable. The staff also noted that LRA items with the same component, material, environment, and aging effect combination are managed for aging by items 3.4.1-15 and 3.4.1-16 instead of items 3.3.1-23 and 3.3.1-24, and these alternative items are consistent with the GALL Report's recommended programs.

(3) LRA Section 3.3.2.2.10.3, is associated with LRA Table 3.3.1, item 3.3.1-25, and addresses the copper-alloy HVAC piping, piping components, and piping elements in the chlorination, screen wash, service water, and waste processing liquid systems, and copper-alloy heat exchanger components in the containment air handling, containment enclosure air handling, and control building air handling systems exposed to condensation (external), which are being managed for loss of material due to pitting, galvanic or crevice corrosion by the External Surfaces Monitoring, Bolting Integrity Program, or Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs.

The criteria in SRP-LR Section 3.3.2.2.10, item 3, 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 GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed in accordance with the acceptance criteria described in BTP RLSB-1. The applicant addressed the further evaluation criteria of the SRP-LR by stating that copper-alloy piping, copper-alloy heat exchanger components, and bolting exposed to condensation (external) will be managed for loss of material due to pitting, galvanic, and crevice corrosion by the External Surfaces Monitoring, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and Bolting Integrity Programs.

The staff's evaluations of the applicant's External Surfaces Monitoring, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and Bolting Integrity Programs are documented in SER Sections 3.0.3.2.14, 3.0.3.2.15, and 3.0.3.1.7, respectively. The staff noted that the applicant's External Surfaces Monitoring Program provides for visual inspection of component surfaces for pitting, crevice, and galvanic corrosion at least once per refueling cycle. The staff also noted that the applicant's Bolting Integrity Program provides for visual inspection of bolting for corrosion. In addition, the staff noted that the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program affords opportunistic visual inspections by qualified personnel in accordance with station-controlled procedures and processes during the pre-planned, periodic system, and component surveillance and maintenance activities. In its review of components associated with LRA Table 3.3.1, item 3.3.1-25, the staff finds that the applicant met the further evaluation criteria. Additionally, the applicant's proposal to manage aging using the External Surfaces Monitoring, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and Bolting Integrity Programs is acceptable because these programs include periodic visual inspections capable of detecting loss of material due to pitting, crevice, or galvanic corrosion.

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 items that apply to LRA Section 3.3.2.2.10.3, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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, referenced in Table 3.3.1, item 3.3.1-26, addresses copper-alloy piping, piping components, and piping elements exposed to lubricating oil, 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 criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material due to pitting and crevice corrosion through examination of susceptible locations in copper-alloy piping, piping components, and copper-alloy heat exchanger components exposed to lubricating oil in the chemical and volume control, diesel generator, miscellaneous equipment, instrument air, service water, switchyard systems.

The staff reviewed LRA Section 3.3.2.2.10.4 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 AMP 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. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil control should be confirmed to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the Lubricating Oil Analysis Program for which a one-time inspection of selected 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's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. In its review of components associated with item 3.3.1-26, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report. Additionally, the applicant stated that the One-Time Inspection Program will be used to examine copper-alloy piping, piping components, and piping elements to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.3.2.2.10, item 4; therefore, the applicant's AMR is consistent with the GALL Report.

(5) LRA Section 3.3.2.2.10.5 is associated with LRA Table 3.3.1, item 3.3.1-27, and addresses stainless steel and aluminum components in auxiliary systems exposed to condensation (internal) or condensation (external), which are being managed for loss of material due to pitting or crevice corrosion. The criteria in SRP-LR Section 3.3.2.2.10, item 5, 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 components exposed to condensation. The SRP-LR also states that a plant-specific AMP should be evaluated to ensure that these aging effects are adequately managed. The applicant addressed the further evaluation criteria of the SRP-LR by identifying several AMPs to manage the aging effect, as described below.

The applicant stated the following:

- The Bolting Integrity Program will be used to manage loss of material due to pitting and crevice corrosion of stainless steel bolting exposed to condensation (external) in the primary component cooling water, screen wash, and service water systems.
- The Compressed Air Monitoring Program will be used to manage loss of material due to pitting, crevice, and galvanic corrosion for aluminum piping and heat exchanger components (after cooler tubes, filter housing, traps) exposed to condensation (internal) in the diesel generator and instrument air systems.
- The External Surfaces Monitoring Program will be used to manage loss of material due to pitting and crevice corrosion of aluminum heat exchanger fins exposed to condensation (external) in the control building air handling system.
- The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will be used to manage loss of material due to

pitting, crevice, and galvanic corrosion of aluminum piping components exposed to condensation in the fire protection system. It will be used to manage loss of material due to pitting and crevice corrosion of stainless steel HVAC drip pans and piping exposed to condensation (internal) in the containment air handling, containment enclosure air handling, and fuel storage building air handling systems.

The staff's evaluations of the applicant's Bolting Integrity Program, Compressed Air Monitoring Program, External Surfaces Monitoring Program, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program are documented in SER Sections 3.0.3.1.7, 3.0.3.2.6, 3.0.3.2.14, and 3.0.3.2.15, respectively. The staff noted that the Bolting Integrity, Compressed Air Monitoring, External Surfaces Monitoring, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs all include visual inspection activities that are capable of detecting loss of material due to pitting, crevice, and galvanic corrosion in aluminum and stainless steel components. These programs implement corrective action if unacceptable indications of loss of material due to pitting, crevice, or galvanic corrosion are found. The staff also noted that the Compressed Air Monitoring Program also includes monitoring of air system quality and preventive activities to reduce the potential for presence of moisture and occurrence of corrosion. The staff further noted that components associated with LRA Table 3.3.1, item 3.3.1-27, addressed by the Bolting Integrity Program, the External Surfaces Monitoring Program, and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program are typically accessible for visual examination during normal operation or routine plant outages. In its review of components associated with LRA Table 3.3.1, item 3.3.1-27, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Bolting Integrity Program, Compressed Air Monitoring Program, External Surfaces Monitoring Program, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable for the following reasons:

- The components associated with LRA Table 3.3.1, item 3.3.1-27, are typically accessible for inspection either during normal operation or routine plant outages.
- Each of the credited programs includes visual inspections that are capable of detecting loss of material due to pitting, crevice, and galvanic corrosion in aluminum and stainless steel components.
- Each credited program includes requirements for implementing corrective actions if unacceptable indications of loss of material due to pitting, crevice, or galvanic corrosion are found.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10, item 5, criteria. For those items that apply to LRA Section 3.3.2.2.10.5, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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, is associated with LRA Table 3.3.1, item 3.3.1-28, and addresses copper-alloy fire protection piping and piping components and tanks in the

diesel generator, instrument air, and fire protection systems exposed to condensation (internal), which are being managed for loss of material due to pitting and crevice corrosion by the Compressed Air Monitoring and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs. The criteria in SRP-LR Section 3.3.2.2.10, item 6, states that loss of material due to pitting and crevice corrosion could occur for copper-alloy 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 AMP to ensure that these aging effects are adequately managed in accordance with the acceptance criteria described in BTP RLSB-1. The applicant addressed the further evaluation criteria of the SRP-LR by stating that copper-alloy piping components exposed to condensation will be managed for loss of material due to pitting and crevice corrosion by the Compressed Air Monitoring and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs.

The staff's evaluations of the applicant's Compressed Air Monitoring and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs are documented in SER Sections 3.0.3.2.6 and 3.0.3.2.15, respectively. In its review of components associated with LRA Table 3.3.1, item 3.3.1-28, the staff finds that the applicant met the further evaluation criteria. Additionally, the staff finds that the applicant's proposal to manage aging using the Compressed Air Monitoring and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs is acceptable because these programs provide for preventive actions, inspections, and detection of aging effects of copper alloys.

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 items that apply to LRA Section 3.3.2.2.10.6, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 addresses loss of material due to pitting and crevice corrosion in stainless steel piping, piping components, and piping elements exposed to soil. LRA Section 3.3.2.2.10.7 is associated with LRA Table 3.3.1, item 3.3.1-29, and addresses stainless steel piping, piping components and piping elements exposed to soil, which are being managed for loss of material due to pitting and crevice corrosion by the Buried Piping and Tanks Inspection Program. The criteria in SRP-LR Section 3.3.2.2.10, item 7, states that the loss of material due to pitting, crevice, and MIC could occur for stainless steel piping, piping components, and piping elements exposed to soil environment. The SRP-LR also states that a plant-specific AMP will be used to manage the loss of material aging effect. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Buried Piping and Tanks Inspection Program will use external coatings and wrappings on buried piping as well as periodic inspections to determine loss of material.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.3.1. In its review of components associated with LRA Table 3.3.1, item 3.3.1-29, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program is acceptable for the following reasons:

- The program includes preventive actions such as external coatings and wrappings installed to industry standard practices and backfill that will not damage the piping or coatings, and some systems are protected by a cathodic protection system.
- Periodic visual inspections will be performed starting 10 years prior to the period of extended operation and extend into both 10-year periods during the period of extended operation to ensure that coatings remain intact or uncoated piping has not degraded.
- Plant-specific operating experience will be used to inform inspection locations.
- Alternatives to direct visual inspection, such as pressure tests or ultrasonic inspections, are capable of detecting piping degradation.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.10, item 7, criteria. For those items that apply to LRA Section 3.3.2.2.10.7, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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).

(8) LRA Section 3.3.2.2.10.8, associated with LRA Table 3.3.1, item 3.3.1-30, addresses loss of material due to pitting and crevice corrosion in stainless steel piping, piping components, and piping elements of the BWR standby liquid control system exposed to sodium pentaborate solution. The applicant stated that this item is not applicable because it is only applicable to BWRs. The staff reviewed the SRP-LR and LRA Section 3.3 and noted that this item is associated only with BWRs; therefore, it finds the applicant's claim acceptable.

3.3.2.2.11 Loss of Material due to Pitting, Crevice, and Galvanic Corrosion

LRA Section 3.3.2.2.11, associated with LRA Table 3.3.1, item 3.3.1-31, addresses loss of material due to pitting, crevice, and galvanic corrosion of copper-alloy piping, piping components, and piping elements that are exposed to treated water. The applicant stated that this item is not applicable because LRA Table 3.3.1, item 3.3.1-31, is applicable to BWRs only. The staff reviewed LRA Sections 2.3.4 and 3.4 and found that there are in-scope copper-alloy instrumentation elements, valve bodies, and heat exchanger components exposed to treated water in the auxiliary steam condensate and feedwater systems. The staff noted that although loss of material due to selective leaching for these components is managed with Selective Leaching of Materials Program, there are no actions identified to manage loss of material due to pitting, crevice, and galvanic corrosion for these components.

By letter dated January 5, 2011, the staff issued RAI 3.3.2.2-1 requesting that the applicant justify why the copper-alloy piping, piping components, and piping elements exposed to treated water would not be vulnerable to pitting, crevice, and galvanic corrosion.

In its response dated February 3, 2011, the applicant stated that auxiliary steam condensate, condensate, and feedwater systems were evaluated under Section 3.4 of the LRA, "Aging Management of Steam and Power Conversion Systems," and, therefore, aligned with Section 3.4.2.2.7.1 and item 3.4.1-15. The staff noted that components under item LRA Table 3.4.1, item 3.4.1-15, are managed for loss of material due to pitting and crevice corrosion in aluminum and copper-alloy piping, piping components, and piping elements exposed to treated water by the One-Time Inspection and Water Chemistry Programs. The staff's evaluations of the applicant's One-Time Inspection and Water Chemistry Programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. The staff finds the applicant's response acceptable because adherence to the water chemistry guidelines through the implementation of the Water Chemistry Program minimizes the presence of contaminants that may lead to pitting and crevice corrosion in those components. The One-Time Inspection Program provides an inspection opportunity to verify the effectiveness of the Water Chemistry Program. The staff's concern described in RAI 3.3.2.2-1 is resolved.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.3.2.2.12 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion

(1) LRA Section 3.3.2.2.12.1 is associated with LRA 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, which are being managed for loss of material due to pitting, crevice, and MIC by the Fuel Oil Chemistry and One-Time Inspection Programs. The staff noted that the LRA states that galvanic corrosion is an additional aging effect that will be managed for the aluminum components in the diesel generator system. The criteria in SRP-LR Section 3.3.2.2.12, item 1, state that loss of material due to pitting, crevice, and MIC could occur for stainless steel, aluminum, and copper-alloy components exposed to fuel oil. The SRP-LR also states that corrosion may occur at locations where contaminants accumulate, and the effectiveness of fuel oil chemistry control should be confirmed to ensure that corrosion does not occur. The SRP-LR further states that a one-time inspection of selected 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 applicant addressed the further evaluation criteria of the SRP-LR by stating it will implement the One-Time Inspection Program to verify the effectiveness of the Fuel Oil Chemistry Program to ensure that these aging effects are adequately managed.

The staff's evaluations of the applicant's Fuel Oil Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.10 and 3.0.3.1.8, respectively. The staff noted that the Fuel Oil Chemistry Program includes activities to monitor fuel oil chemistry quality, remove water, and clean and inspect the tanks. The staff also noted that the One-Time Inspection Program will inspect a sample of components in systems that contain fuel oil for evidence of effective management of loss of material. In its review of components associated with LRA Table 3.3.1, item 3.3.1-32, the staff finds the applicant's proposal to manage aging using the Fuel Oil Chemistry and One-Time Inspection Programs acceptable because the Fuel Oil Chemistry Program includes activities to ensure contaminants that could cause corrosion do not accumulate. Additionally, the One-Time Inspection Program provides for visual inspections to confirm the effectiveness of the Fuel Oil Chemistry Program, which is consistent with the guidance in the SRP-LR.

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 items that apply to LRA Section 3.3.2.2.12.1, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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, referenced in Table 3.3.1, item 3.3.1-33, addresses stainless steel piping, piping components, and piping elements exposed to lubricating oil, which are being manage for loss of material due to pitting, crevice, and MIC by the Lubricating Oil Analysis 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 used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material due to pitting, crevice, and MIC through examination of susceptible locations in stainless steel piping, stainless steel drip pan components, stainless steel flame arrestor, stainless steel tank, and stainless steel heat exchanger components exposed to lubricating oil in the chemical and volume control, diesel generator, fire protection, instrument air, miscellaneous equipment, oil collection for reactor coolant pumps, and switchyard systems.

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 MIC could occur in stainless steel piping, piping components, and piping elements exposed to lubricating oil. The SRP-LR also states that the existing AMP relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby an environment that is not conducive to corrosion. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil control should be confirmed to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the Lubricating Oil Analysis Program for which a one-time inspection of selected 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's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. In its review of components associated with item 3.3.1-33, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report. Additionally, the applicant stated that the One-Inspection Program will be used to examine stainless steel piping, piping components, piping elements, and heat exchanger components to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.3.2.2.12, item 2; therefore, the applicant's AMR is consistent with the GALL Report.

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 the items that apply to LRA Section 3.3.2.2.12.2, the staff determined that the LRA is consistent with the GALL Report, and the applicant demonstrated that the effect 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).

3.3.2.2.13 Loss of Material Due to Wear

LRA Section 3.3.2.2.13 is associated with LRA Table 3.3.1, item 3.3.1-34, and addresses elastomer seals and components exposed to air-indoor uncontrolled (internal or external) which are being managed for loss of material due to wear by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for internal surfaces and the External Surfaces Monitoring Program for external surfaces. The criteria in SRP-LR Section 3.3.2.2.13 state that loss of material due to wear could occur in the elastomer seals and components exposed to air-indoor uncontrolled (internal or external). The SRP-LR also states that the GALL Report recommends further evaluation of a program to ensure that the aging effects are adequately managed. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is adequate to manage the aging effects on the internal surfaces of these components, and the External Surfaces Monitoring Program is adequate to manage the aging effects on the external surfaces of these components.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program provides for inspections of opportunity, performed during pre-planned, periodic system and component surveillances or during maintenance activities when the systems are opened and the surfaces are made accessible for visual inspection. The staff also noted that for elastomeric materials, the program uses tactile techniques, which include scratching, bending, folding, stretching, and pressing in conjunction with the visual examinations.

The staff's evaluation of the applicant's Inspection of External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff noted that the External Surfaces Monitoring Program uses periodic system inspections and walkdowns to monitor for materials degradation and leakage. The staff also noted that for elastomeric materials, the program uses tactile techniques, which include scratching, bending, folding, stretching, and pressing in conjunction with the visual examinations.

The staff finds that the applicant met the further evaluation criteria and the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and the External Surfaces Monitoring Program is acceptable because the program uses visual inspections and tactile techniques that are capable of detecting loss of material due to wear before loss of intended function.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.13 criteria. For those items that apply to LRA Section 3.3.2.2.13, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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).

3.3.2.2.14 Loss of Material Due to Cladding Breach

The staff reviewed LRA Section 3.3.2.2.14 against the criteria in SRP-LR Section 3.3.2.2.14.

LRA Section 3.3.2.2.14, associated with LRA Table 3.3.1, item 3.3.1-35, addresses loss of material due to cladding breach in pump casings of steel with stainless steel cladding exposed to treated borated water. The applicant stated that this item is not applicable because the plant's CVCS does not contain pump casings comprised of steel with stainless steel cladding. The staff reviewed LRA Sections 2.3.3 and 3.3 and the UFSAR and confirmed that no in-scope pump casings of steel with stainless steel cladding exposed to treated borated water are present in the auxiliary systems; therefore, it finds the applicant's claim acceptable.

3.3.2.2.15 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.3.2.3 Aging Management Review Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.3.2-1 through 3.3.2-45, 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 3.3.2-1 through 3.3.2-45, via Notes F–J, the applicant indicated which combinations of component type, material, environment, and AERM do not correspond to an 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 item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR 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 item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the 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 if the applicant 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.

3.3.2.3.1 Auxiliary Boiler—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 auxiliary boiler system component groups.

In LRA Tables 3.3.2-1, 3.3.2-17, and 3.3.2-40, the applicant stated that the steel bolting exposed to air-outdoor is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because even though steel bolting exposed to air-outdoor is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, Table IX.C of the GALL Report states that steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to general, pitting, and crevice corrosion. The staff noted that the applicant addressed loss of material in additional items for each of these components; therefore, the aging effect of concern is loss of preload, which is addressed in the AMR.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload of steel bolting exposed to air-outdoor in the auxiliary system, the GALL Report has items for other material bolting exposed to air-outdoor managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload. Additionally, the program inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

In LRA Tables 3.3.2-1, 3.3.2-12, and 3.3.2-40, the applicant stated that aluminum valve body, flame arrestor, and piping and fittings exposed to air-outdoor (external) are being managed for loss of material by the External Surfaces Monitoring Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because, even though the GALL Report does not have an aging effect or AMP for aluminum exposed to air-outdoor (external), the GALL Report does state that aluminum materials exposed to condensation are subject to loss of material due to pitting and crevice corrosion. The GALL Report also states that exposure to outdoor weather conditions can be considered a condensation environment.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff finds that the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the program uses periodic visual inspections that would detect loss of material in aluminum components.

In LRA Tables 3.3.2-1 and 3.3.2-9, the applicant stated that aluminum valves and galvanized steel damper housings exposed to air-outdoor (internal) are being managed for loss of material due to general, pitting, and crevice corrosion with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Table IX.D of the GALL Report states that the outdoor air environment includes moist, possibly salt laden, air where the component is exposed to local weather conditions, including precipitation and wind. Section VII of the GALL Report states that aluminum and steel components exposed to condensation or raw water are susceptible to loss of material due to general, pitting, and crevice corrosion.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. 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 the program includes periodic visual inspections performed during maintenance and surveillance activities, which can identify localized discoloration and surface irregularities such as rust, scale, deposits, and surface pitting that could result in a loss of the component-intended function.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.2 Boron Recovery System—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 boron recovery system component groups.

In LRA Tables 3.3.2-2, 3.3.2-3, 3.3.2-4, 3.3.2-9, 3.3.2-10, 3.3.2-11, 3.3.2-12, 3.3.2-16, 3.3.2-19, 3.3.2-20, 3.3.2-21, 3.3.2-22, 3.3.2-24, 3.3.2-25, 3.3.2-29, 3.3.2-30, 3.3.2-31, 3.3.2-32, 3.3.2-33, 3.3.2-35, 3.3.2-37, 3.3.2-39, 3.3.2-42, 3.3.2-44, and 3.3.2-45, the applicant stated that the stainless steel bolting exposed to air-indoor is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though stainless steel bolting exposed to air-indoor is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, Table IX.C of the GALL Report states that stainless steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion and cracking due to SCC. The staff noted that the environment of interest, air-indoor, would not induce SCC or loss of material in stainless steel material because stainless steel is inherently resistant to corrosion in the air-indoor environment. Therefore, the aging effect of concern is loss of preload, which is addressed in the AMR.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload of stainless steel bolting exposed to air-indoor in the auxiliary system, the GALL Report has items for other material bolting exposed to air-indoor managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload. Additionally, the program inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.3 Chemical and Volume Control System—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 CVCS component groups.

The staff's evaluation for stainless steel bolting, exposed to air-indoor, and managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

In LRA Table 3.3.2-3, the applicant stated that the nickel-alloy flexible hoses exposed to treated borated water are being managed for loss of material by the Water Chemistry Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because even though nickel alloys exposed to treated borated water are not specifically addressed in the GALL Report, Chapter VII of the GALL Report indicates that nickel alloys exposed to aqueous environments are susceptible to loss of material.

The staff's evaluation of the applicant's Water Chemistry Program is documented in SER Section 3.0.3.1.2. The staff noted that the Water Chemistry Program relies upon periodic monitoring and control of detrimental contaminants in the water to manage loss of material. The staff also notes that the GALL Report's guidance for loss of material of stainless steel in treated borated water is part of the Water Chemistry Program, and this aging effect would be very similar to that of nickel alloys in treated borated water. The staff finds the applicant's proposal to manage aging using the Water Chemistry Program acceptable because it employs the use of chemistry sampling to ensure that chemical impurities are minimized to reduce aging due to loss of material, which is similar to guidance observed in the GALL Report.

In LRA Tables 3.3.2-3, 3.3.2-12, 3.3.2-15, and 3.3.2-23, the applicant stated that elastomer flexible hose exposed to fuel oil or lubricating oil (internal) are being managed for hardening and loss of strength with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because the GALL Report, in Table IX.C, states that elastomers are susceptible to hardening and loss of strength at temperatures over about 95 °F (35 °C) or when exposed to additional aging factors such as ozone, oxidation, and radiation. The staff noted that the environment of interest, lubricating oil (internal), has the potential for being in the temperature range for elastomer susceptibility to aging; therefore, the aging effect of concern is hardening and loss of strength, which is addressed in the AMR.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable for the following reasons:

- The program includes periodic visual inspections performed during maintenance and surveillance activities, which can identify localized discoloration and surface irregularities.

- The program includes non-visual examinations, such as scratching, which will screen for residues and breakdown of the material, and stretching and pressing, which will evaluate the material resiliency to determine if hardening and loss of strength are occurring that could result in a loss of the component-intended function.

In LRA Tables 3.3.2-3, 3.3.2-5, 3.3.2-6, 3.3.2-7, 3.3.2-8, 3.3.2-11, 3.3.2-16, 3.3.2-18, 3.3.2-20, 3.3.2-23, 3.3.2-28, 3.3.2-35 and 3.3.2-39, the applicant stated that the elastomer flexible hoses and flexible connectors exposed to air with borated water leakage (external) are being managed for hardening and loss of strength by the External Surfaces Monitoring Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because the GALL Report, item VII.A3-1, states that elastomers are susceptible to hardening and loss of strength, due to elastomer degradation when exposed to treated borated water. The environment of interest, air with borated water leakage, contains borated water that would make the material susceptible to hardening and loss of strength, which is addressed in the AMR.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff noted that the applicant's program includes non-visual examinations such as scratching to determine if scale or residues are present or determine if there is a breakdown of material, bending, or folding of the elastomer to detect cracking that initiates at the surface, stretching, and pressing to determine the resistance of the material to hardening effects, and pressing to gauge the materials resiliency. The staff finds that the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the program includes periodic visual inspections as well as non-visual tactile examinations to detect hardening and loss of strength of the component.

In LRA Tables 3.3.2-3, 3.3.2-29, 3.3.2-37, and 3.3.2-40, the applicant stated that for nickel-alloy components exposed to air with borated water leakage there is no aging effect and no AMP is proposed. The AMR items cite generic note G and plant-specific note 1. Plant-specific note 1 states the following:

> NUREG-1801 does not include air with borated water leakage for nickel-alloy components. Similar to V.F-13 for stainless steel, there are no aging effects for nickel alloy in air with borated water leakage. Additionally, the American Welding Society (AWS) "Welding Handbook," (Seventh Edition, Volume 4, 1982, Library of Congress) identifies that nickel chromium alloy materials that are alloyed with iron, molybdenum, tungsten, cobalt or copper in various combinations have improved corrosion resistance.

The staff reviewed the associated items in the LRA and confirmed that the applicant's use of generic note G for these items is appropriate in that the GALL Report, Revision 1, does not include entries for nickel alloys exposed to air with borated water leakage. The staff notes that the GALL Report, Revision 2, dated December 31, 2010, does include entries for nickel alloys exposed to air with borated water leakage. These entries indicate that no AERM is present for this material environment combination. The staff also notes these items in Revision 2 of the GALL Report are based in part on EPRI Report 1000975, "Boric Acid Corrosion Guidebook, Revision 1." This report contains data (p. 4–43) showing that "[t]here was no measurable corrosion of stainless steel piping surfaces or Inconel weld metal joining the stainless steel and carbon steel piping sections." The staff, therefore, concurs with the applicant's assessment that aging management is not necessary for nickel-alloy components exposed to air with borated water leakage.

In LRA Table 3.3.2-3, 3.3.2-4, 3.3.2-5, 3.3.2-11, 3.3.2-16, 3.3.2-19, 3.3.2-29, 3.3.2-30, 3.3.2-31, 3.3.2-35, 3.3.2-37, and 3.3.2-39, the applicant stated that, for glass piping elements exposed to air-with borated water leakage (external), there is no aging effect and no AMP is proposed. The AMR items cites generic note G. The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because the GALL Report, item V.F-9, states that, for an environment of treated borated water there is no AERM and no recommended AMP. Additionally, the air with borated water leakage environment is no more severe than the treated borated water environment.

In response to RAI 3.2.2.2.4.2-1A, by letter dated June 2, 2011, the applicant amended the LRA by revising LRA Table 3.3.2-3 to include stainless steel heat exchanger components exposed to treated borated water that are being managed for reduction of heat transfer due to fouling by the Water Chemistry Program. The AMR items cite generic note H.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because the GALL Report recommends managing reduction of heat transfer for heat exchanger components in treated water, and treated borated water is comparable to treated water with regard to the potential for reduction of heat transfer due to fouling.

However, the staff finds the applicant’s use of only the Water Chemistry Program to manage reduction of heat transfer unacceptable because the guidance in the SRP-LR and GALL Report was revised in LR-ISG-2011-01, “Aging Management of Stainless Steel Structures and Components in Treated Borated Water,” to add the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to manage stainless steel components for loss of material, cracking, and reduction of heat transfer in treated borated water environments that are not controlled to low oxygen levels. The staff noted that, prior to the issuance of LR-ISG-2011-01, the SRP-LR and GALL Report guidance inappropriately credited the boron in borated water as a corrosion inhibitor in place of other aging management activities.

By letter dated May 29, 2012, the staff issued RAI 3.2.1.48-1 requesting that the applicant describe how the effectiveness of the Water Chemistry Program to manage reduction of heat transfer will be verified for stainless steel components exposed to treated borated water with greater than 5 ppb oxygen. Pending the staff’s review of the applicant’s response, this issue is identified as Open Item OI 3.2.2.1-1.

On the basis of its review, pending resolution of Open Item OI 3.2.2.1-1, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.4 Chlorination System—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 chlorination system component groups.

The staff's evaluation for stainless steel bolting, exposed to air-indoor and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

In LRA Table 3.3.2-4, the applicant stated that the stainless steel bolting exposed to condensation is being managed for loss of material by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though stainless steel bolting exposed to condensation is not specifically addressed in the GALL Report, Table IX.C of the GALL Report states that stainless steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion and cracking due to SCC. The staff noted that the environment of interest, condensation, would not induce SCC in stainless steel material because stainless steel is inherently resistant to SCC in the condensation environment and becomes susceptible to SCC only at temperatures above 140 °F (60 °C); therefore, the aging effect of concern is loss of material, which is addressed in the AMR.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of material of stainless steel bolting exposed to condensation in the auxiliary system, the GALL Report has items for loss of material of other material bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program inspects the bolting through periodic visual inspections to verify that the aging effect, loss of material, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

In LRA Tables 3.3.2-4, 3.3.2-9, 3.3.2-11, 3.3.2-20, 3.3.2-26, and 3.3.2-35, the applicant stated that for polymer [polyvinyl chloride (PVC), polyvinylidene fluoride (PVDF), polypropylene, fluoropolymer, polycarbonate, plastic and polyolefin] piping, piping components, and piping elements, flexible hose, tanks, and instrument elements exposed to air-indoor uncontrolled (internal or external) and air-indoor controlled external environments, there is no aging effect, and no AMP is proposed. The AMR items cite generic note F. These items also cite plant-specific Notes 1 or 2. Plant-specific note 2 states the following:

> Unlike metals, polymers do not display corrosion rates. Rather than depending on an oxide layer for protection, they depend on chemical resistance to the environment to which they are exposed. The plastic is either completely resistant to the environment or it deteriorates. Therefore, acceptability for the use of polymers within a given environment is a design driven criterion. Once the appropriate material is chosen, the system will have no aging effects. This is consistent with plant operating experience.

The staff noted that, as identified in *Engineering Materials Handbook—Engineering Plastics*, ASM International, Copyright 1988, rigid polymers are unaffected by water, concentrated alkalis, non-oxidizing acids, oils, ozone, sunlight, or humidity changes. The staff also noted that, unlike metals, thermoplastics do not display corrosion rates, and rather than depend on an oxide layer for protection, they depend on chemical resistance to the environments to which they are exposed and the use of thermoplastics in power plant environments is a design-driven criterion. The staff further noted that thermoplastic materials are impervious and, once selected for the environment, will not have any significant age-related degradation. The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because there is no indication in the industry that polymers or thermoplastics exposed to an internal or external indoor air environment have any aging effects requiring management. Additionally, the generally low operating temperatures and historically good chemical resistance data for polymer components, combined with a lack of historically negative operating experience, indicate that polymers are not likely to experience any degradation from the non-aggressive indoor air.

In LRA Tables 3.3.2-4, 3.3.2-15, and 3.3.2-36, the applicant stated that, for fiberglass piping and fittings and filter housings exposed to condensation (external) or raw water (internal), there is no aging effect, and no AMP is proposed. The AMR items cite generic note F and plant-specific Notes 1, 5, or 6, which state that "[f]iberglass components in Condensation environment (external) or Raw Water environment (internal) are not exposed to high levels of ultraviolet radiation, high temperatures, or ozone, and therefore have no aging effects that require aging management. This is consistent with plant operating experience." The staff reviewed the associated items in the LRA and found that fiberglass piping exposed to condensation (external) or raw water (internal) is not specifically addressed in the GALL Report; however, the staff noted that the environments of interest could cause water infiltration into the fiberglass, which could induce blistering and spalling or cracking. By letter dated January 5, 2011, the staff issued RAI 3.3.2.3.4-1 requesting that the applicant state why the specific specification and grade of fiberglass material used in these components is not susceptible to blistering and spalling or cracking when exposed to condensation environment (external) or raw water environment (internal) or propose how the aging effects will be managed.

In its response dated February 3, 2011, the applicant stated that portions of the chlorination system, and all of the fire protection system's fiberglass piping, is constructed of an epoxy resin type of material. Based on technical input from the manufacturer, there is no industry experience of blistering, spalling, or cracking due to water absorption in fiberglass piping constructed with the epoxy resin. The applicant also stated that fiberglass reinforced vinyl ester pipe is used in the chlorination system in the service water pumphouse and the intake and discharge structures to supply chlorinated raw water to the pump forebay and to the seawater inlet. The maximum design temperature for this piping of 100 °F and the maximum seawater inlet temperature is 65 °F at Seabrook. The applicant further stated that only hot water in the range of 170–180 °F or above can cause blistering, spalling, or cracking in vinyl ester resin based fiberglass pipe. The applicant stated that the travelling screen system uses fiberglass traveling screen enclosures, which are only exposed to condensation or raw water in the spray form.

The staff reviewed *The Corrosion Resistant Materials Handbook*, by D. J. De Renzo and Ibert Mellan, and found that both fiberglass reinforced epoxy pipe and reinforced vinyl ester resin pipe are acceptable for use up to 200 °F in brine and 10 percent salt water and chlorinated water up 200 ppm chlorine. The staff also noted that reinforced vinyl ester resin pipe is acceptable for use in chlorine saturated brine up 150 °F and saturated chlorinated water up to 200 °F; however, fiberglass reinforced epoxy pipe is not recommended under these conditions.

The staff reviewed the fiberglass items in the LRA associated with the fire protection and screen wash system and confirmed that no aging effect is applicable for this component, material, and environment combination for the following reasons:

- For the fire protection system, LRA Table 3.3.2-15, the components are constructed of an epoxy resin type of material, which does not have aging effects until exposed to temperatures above 170 °F, which is above the fire protection systems design temperature.

- For the screen wash system, LRA Table 3.3.2-36, the components are only exposed to raw water as a spray or condensation. Neither of these environments have a driving force for water penetration and blistering.

Based on a review of the UFSAR, the staff could not determine the chlorine level of the water in the chlorination system such that a determination of no aging effects could be warranted. By letter dated March 30, 2011, the staff issued a followup to RAI 3.3.2.3.4-1 requesting that the applicant state the chlorine concentration for in-scope fiberglass pipe in the chlorination system. If it exceeds 200 ppm, the staff asked that the applicant state why there is no aging effect or propose an AMP.

In its response dated April 22, 2011, the applicant stated that the components exposed to chlorine are constructed of fiberglass reinforced vinyl ester or bisphenol-A polyester. The applicant also stated that, based on input from the vendor of the components, given the operating parameters of the system—less than 65 °F, pH greater than 10, and no direct UV exposure—and plant-specific operating experience to date, there is no potential aging effect.

The staff did not find the applicant's response acceptable because, based on independent research, the staff does not agree with the applicant's assessment that there is no potential aging effect for these components. While the applicant's response to the RAI, and the staff's independent research, established that the materials are suitable for the design parameters of the system, proper design does not establish the basis for a 60-year life with no aging effects when the environment is an oxidizer and the material is an organic polymer. Therefore, by letter dated May 23, 2011, the staff issued a followup to RAI 3.3.2.3.4-1 requesting that the applicant state what inspections have been performed to establish a baseline of operating experience and what inspections will be conducted to manage aging of the fiberglass piping and fittings in the chlorination system exposed to raw water, including sodium hypochlorite.

In its response dated June 2, 2011, the applicant stated that, during the April 2011 RFO, the chlorination system piping was disassembled, and the piping was found to be in excellent condition with no signs of age-related degradation. The applicant revised the LRA to include a one-time inspection of the chlorination system fiberglass piping to validate that no aging effect is occurring. The applicant also revised its UFSAR supplement, LRA Section A.2.1.20, to reflect that the One-Time Inspection Program will be used to manage the aging effects of cracking, blistering, and change in color (i.e., material properties) for fiberglass piping in the chlorination system.

The staff finds the applicant's response acceptable for the following reasons:

- The applicant identified the correct potential aging effects for this material and environment combination.
- The applicant revised the LRA to include a one-time inspection of fiberglass piping in the chlorination system to verify that aging does not occur.
- The One-Time Inspection Program includes determination of an appropriate sample size, identification of inspection locations, and visual inspections that can detect the potential aging effects.

The staff's concern described in RAI 3.3.2.3.4-1 is resolved.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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 Tables 3.3.2-4, 3.3.2-9, and 3.3.2-37, the applicant stated that for polymer (PVC) piping and fittings, and filter housing exposed to condensation (internal or external) environment, there is no aging effect, and no AMP is proposed. The AMR items cite generic note F. These items also cite plant-specific notes 1 or 2. Plant-specific note 2 states the following:

> Unlike metals, polymers do not display corrosion rates. Rather than depending on an oxide layer for protection, they depend on chemical resistance to the environment to which they are exposed. The plastic is either completely resistant to the environment or it deteriorates. Therefore, acceptability for the use of polymers within a given environment is a design driven criterion. Once the appropriate material is chosen, the system will have no aging effects. This is consistent with plant operating experience.

The staff noted that, as identified in *Engineering Materials Handbook—Engineering Plastics*, American Society for Metals International, Copyright 1988, rigid polymers are unaffected by water, concentrated alkalis, non-oxidizing acids, oils, ozone, sunlight, or humidity changes. The staff also noted that, unlike metals, thermoplastics do not display corrosion rates, and rather than depend on an oxide layer for protection, they depend on chemical resistance to the environments to which they are exposed and the use of thermoplastics in power plant environments is a design-driven criterion. The staff further noted that thermoplastic material is impervious and, once selected for the environment, will not have any significant age-related degradation. The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because there is no indication in the industry that polymers or thermoplastics exposed to an internal or external condensation environment have any aging effects requiring management. Additionally, the generally low operating temperatures and historically good chemical resistance data for polymer components, combined with a lack of historically negative operating experience, indicate that polymers are not likely to experience any degradation from the non-aggressive condensation environment.

In LRA Tables 3.3.2-4, 3.3.2-11, 3.3.2-26, and 3.3.2-37, the applicant stated that for polymeric piping, piping components, piping elements, and filter housings exposed to raw water environment, there is no aging effect, and no AMP is proposed. The AMR items cite generic note F. These items also cite plant-specific Notes 1 or 2. Plant-specific note 2 states the following:

> Unlike metals, polymers do not display corrosion rates. Rather than depending on an oxide layer for protection, they depend on chemical resistance to the environment to which they are exposed. The plastic is either completely resistant to the environment or it deteriorates. Therefore, acceptability for the use of polymers within a given environment is a design driven criterion. Once the appropriate material is chosen, the system will have no aging effects. This is consistent with plant operating experience.

The staff reviewed the associated items in the LRA. The staff noted that polymer degradation occurs when it is exposed to high temperature or continuously exposed to ultraviolet rays and some chemicals. LRA Table 3.0-1 defines raw water and states that it may contain contaminants including oil and boric acid, depending on the location, as well as originally treated water that is not monitored by a chemistry program. The staff also noted that it is, therefore, possible that these polymeric components could be exposed to an environment of raw water that includes oil, microorganisms, or other chemicals and, therefore, could potentially have an aging effect of cracking or blistering. By letter dated January 5, 2011, the staff issued RAI 3.3.2.3.4-1 requesting that the applicant state why polymeric components in LRA Tables 3.3.2-4 and 3.3.2-26, exposed to a raw water environment as defined in LRA Table 3.0-1, will not exhibit any aging effects that require management.

In its response dated February 3, 2011, the applicant stated that the instrument element in LRA Table 3.3.2-4 is manufactured from PVDF, which is a specialty plastic material in the fluoropolymer family and is used generally in applications requiring the highest purity, strength, and resistance to solvents, acids, bases, and heat. The applicant also stated that the material is rugged and unusually resistant to many chemical solvents, bases, and acids. The applicant further stated that the instrument element is correctly identified as no aging management required.

The staff reviewed the applicant’s response and confirmed that no aging effect is applicable for this component, material, and environment combination because the EPRI Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools Technical Report, Revision 4, states that PVDF is highly corrosion resistant and shows no effect in acids or alkalies. It also shows that PVDF is resistant to strong acids and organic solvents and has a continuous heat resistance of 300 °F.

For the filter housing, the applicant responded that it had inadvertently listed the material as polymer (PVC), and this strainer had been replaced with a Hastealloy strainer, which is a nickel-alloy material. The staff’s evaluation of nickel alloy in an internal environment of raw water is documented in SER Section 3.3.2.1.16. The staff’s evaluation of nickel alloy in an external environment of condensation is documented in SER Section 3.3.2.3.15.

The applicant further stated that, in Table 3.3.2-4, piping and fittings were inadvertently shown as polymer (PVC). The applicant stated that although there is polymer (PVC) piping in the chlorination system, none of it is within the scope of license renewal. Therefore, in Table 3.3.2-4, on page 3.3-190, the applicant deleted these items. The staff finds the applicant’s deletion of these AMR lines from LRA Table 3.3.2-4 acceptable because the components are not within the scope of license renewal.

The applicant stated that in LRA Table 3.3.2-26, the applicable PVC piping and valves are associated with the sump pumps in the intake and discharge transition structures. The applicant also stated that these sump pumps collect seawater leakage from circulating water and service water system piping and components in those buildings as well as groundwater in-leakage and condensation in the building, and there are no contaminants, including oil and boric acid, normally found in sumps that would result in an aging effect requiring management. The staff reviewed the applicant’s response and confirmed that no aging effect is applicable for this component, material, and environment combination because the EPRI Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools Technical Report, Revision 4, states that polymers such as PVC are resistant to seawater environments up to temperatures of 150 °F. The staff noted that UFSAR Table 9.2-2 states that the design temperature of components in the service water systems is 200 °F; however, given that these components are associated with sump pumps, it is not expected that normal operating temperature of the in-scope piping would exceed 150 °F.

Based on its review, as described above, the staff's concern described in RAI 3.3.2.3.4-1 is resolved.

The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for these component, material, and environment combinations because polymers such as PVDF, PVC, and polypropylene are highly resistant to solvents, acids, and bases, which is consistent with industry operating experience.

The staff's evaluation for glass piping elements exposed to air-with borated water leakage (external) with no AERM and no recommended AMP, citing generic note G, is documented in Section 3.3.2.3.3.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR result of material, environment, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.5 Containment Air Handling System—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 containment air handling system component groups.

In LRA Tables 3.3.2-5 and 3.3.2-7, the applicant stated that copper-alloy heat exchanger components (cooling coil and cooling coil fins) exposed to condensation (external) are being managed for reduction in heat transfer by the External Surfaces Monitoring Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. The GALL Report, item VII.F1-16, states that copper-alloy components exposed to condensation are susceptible to loss of material, which is addressed in other AMR items. Additionally, the function of the components of interest is to provide heat transfer; therefore, any accumulation of dirt, debris, or scale would prevent the component from performing its intended function, which is addressed in these AMR items.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff noted that the External Surfaces Monitoring Program includes visual inspections of the external surfaces of components subject to an AMR to identify the aging effect of reduction of heat transfer. The staff finds that the applicant's proposal to manage aging using the External Surfaces Monitoring Program is acceptable because the program uses periodic visual inspections that would identify corrosion discoloration and accumulation of dirt, scale, or debris indicative of fouling and, thus, detect a reduction in heat transfer.

In LRA Tables 3.3.2-5, 3.3.2-6, 3.3.2-7, 3.3.2-8, 3.3.2-18, and 3.3.2-28, the applicant stated that the elastomer flexible connectors exposed to air with borated water leakage (external) are being managed for loss of material by the External Surfaces Monitoring Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because the GALL Report, item VII.A3-1, indicates that elastomers are susceptible to hardening and loss of strength due to elastomer degradation when exposed to treated borated water, which is addressed in other AMR items. The applicant also identified that the material is subject to loss of material when exposed to the environment of interest, air with borated water leakage, which is addressed the AMR items.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff noted that the applicant's program includes non-visual examinations, such as scratching, to determine if scale or residues are present. These examinations also determine if there is a breakdown of material, bending, or folding of the elastomer to detect cracking that initiates at the surface, stretching, and pressing to determine the resistance of the material to hardening effects, and pressing to gauge the materials resiliency to maintain its strength. The staff finds that the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the program includes periodic visual inspections as well as non-visual tactile examinations to detect loss of material from the component.

The staff's evaluation for elastomer flexible connectors and flexible hose exposed to air with borated water leakage (external), which are being managed for hardening and loss of strength by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.3.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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 Containment Air Purge System—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 containment air purge system component groups.

The staff's evaluation for elastomer flexible connectors and flexible hose exposed to air with borated water leakage (external), which are being managed for hardening and loss of strength by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for elastomer flexible connectors exposed to air with borated water leakage (external), which are being managed for loss of material by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.5.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.7 Containment Enclosure Air Handling System—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 containment enclosure air handling system component groups.

The staff's evaluation for elastomer flexible connectors and flexible hose exposed to air with borated water leakage (external), which are being managed for hardening and loss of strength by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for copper-alloy heat exchanger components exposed to condensation (external), which are being managed for reduction in heat transfer due to fouling by the External Surfaces Monitoring Program citing generic note G, is documented in Section 3.3.2.3.5.

The staff's evaluation for elastomer flexible connectors exposed to air with borated water leakage (external), which are being managed for loss of material by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.5.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.8 Containment Online Purge System—Aging Management Evaluation—LRA Table 3.3.2-8

The staff reviewed LRA Table 3.3.2-8, which summarizes the results of AMR evaluations for the containment online purge system component groups.

The staff's evaluation for elastomer flexible connectors and flexible hose exposed to air with borated water leakage (external), which are being managed for hardening and loss of strength by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for elastomer flexible connectors exposed to air with borated water leakage (external), which are being managed for loss of material by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.5.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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 Control Building Air Handling System—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 control building air handling systems component groups.

The staff's evaluation for galvanized steel damper housing exposed to air-outdoor (internal), which are being managed for loss of material by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and cite generic note G, is documented in SER Section 3.3.2.3.1.

The staff's evaluation for stainless steel bolting exposed to air-indoor, which are being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for glass piping elements, exposed to air-with borated water leakage (external) with no AERM and no recommended AMP citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for polymer (PVC) piping and fittings and filter housing exposed to condensation (internal or external) environment, with no aging effect and no AMP proposed citing generic note F, is documented in SER Section 3.3.2.3.4.

The staff's evaluation for polymer (PVC, PVDF, polypropylene, fluoropolymer, polycarbonate, plastic and polyolefin) piping, piping components, and piping elements, flexible hose, tanks, and instrument elements exposed to air-indoor uncontrolled (internal or external) and air-indoor controlled external environments, with no aging effect and no AMP proposed citing generic note F, is documented in SER Section 3.3.2.3.4.

In LRA Table 3.3.2-9, the applicant stated that elastomer flexible connectors exposed to air-indoor controlled (internal) are being managed for hardening and loss of strength and loss of material with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. The GALL Report, Table IX.C, states that elastomers are susceptible to hardening and loss of strength at temperatures over about 95 °F (35 °C) and when exposed to additional aging factors such as ozone, oxidation, and radiation. The staff noted that the environment of interest, air-indoor controlled (internal), has the potential of being in the temperature range for elastomer susceptibility to aging. Additionally, the GALL Report, item VII.F1-6, indicates that elastomer seals and components are susceptible to loss of material or wear when exposed to an air-indoor uncontrolled (internal) environment. Therefore, the staff noted that the aging effects of concern are hardening, loss of strength, and loss of material, which are addressed in the AMR.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable for the following reasons:

- The program includes periodic visual inspections performed during maintenance and surveillance activities which can identify localized discoloration and surface irregularities.

- The program includes non-visual examinations such as scratching, which will screen for residues and breakdown of the material, and stretching and pressing, which will evaluate the material resiliency to determine if hardening and loss of strength or loss of material is occurring that could result in a loss of the component-intended function.

In LRA Table 3.3.2-9, the applicant stated that stainless steel instrumentation elements, piping and fittings, and valve bodies internally exposed to air-outdoor are being managed for loss of material due to pitting and crevice corrosion with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and noted that, even though stainless steel instrumentation elements, piping and fittings, and valve bodies exposed to air-outdoor are not specifically addressed in the GALL Report, Table IX.C of the GALL Report states that stainless steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion and cracking due to SCC. The staff noted that given the plant's proximity to the ocean, stainless steel instrumentation elements, piping and fittings, and valve bodies internally exposed to the air-outdoor environment would be susceptible to cracking due to SCC. However, the staff noted that the applicant did not identify cracking due to SCC as an AERM for these components. By letter dated February 24, 2011, the staff issued RAI 3.3-1 requesting that the applicant justify its management of this material, environment, AERM, and AMP combination.

In its response dated March 22, 2011, the applicant stated that SCC has been added as an aging mechanism for stainless steel components exposed to an air-outdoor environment. The applicant added new AMR items to manage cracking using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff finds the applicant's response acceptable because the applicant modified the LRA to include cracking due to SCC as an applicable aging effect for stainless steel components exposed to outdoor air and will use either magnified visual inspections or ultrasonic inspections, which are capable of detecting cracking. The staff's concern described in RAI 3.3-1 is resolved.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff finds the applicants proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable for the following reasons:

- The program includes periodic visual inspections performed during maintenance and surveillance activities, which can identify localized discoloration and surface irregularities such as rust, scale or deposits, and surface pitting.
- The program includes either magnified visual inspection or ultrasonic inspection to determine if material degradation is occurring that could result in a loss of the component-intended function.

In LRA Table 3.3.2-9, the applicant stated that for copper-alloy piping, fittings, and valves exposed to air-indoor controlled (external), there is no aging effect, and no AMP is proposed. The AMR items cite generic note G and plant-specific Notes 11 and 12. Notes 11 and 12 state that NUREG-1801 does not include air-indoor controlled for copper alloy and copper alloy greater than 15 percent zinc components. Similar to V.F-3 for copper alloy and copper alloy greater than 15 percent zinc in air-indoor uncontrolled, there are no aging effects for copper alloy and copper alloy greater than 15 percent zinc in air-indoor controlled. The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination. GALL item V.F.3 for copper alloy exposed to uncontrolled indoor air bounds the consideration for these components in controlled indoor air, and item V.F.3 states there are no aging effects for copper-alloy components in uncontrolled indoor air.

In LRA Table 3.3.2-9, the applicant stated that for stainless steel valve bodies, thermowells, piping and fittings, and instrumentation elements exposed to air-indoor controlled (external), there is no aging effect, and no AMP is proposed. The AMR items cite generic note G and plant-specific note 10, which states that NUREG-1801 does not include air-indoor controlled for stainless steel components. However, similar to VII.J-15 for stainless steel in air-indoor uncontrolled, there are no aging effects for stainless steel in air-indoor controlled.

The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because controlled indoor air contains less moisture than uncontrolled indoor air; therefore, uncontrolled indoor air can be considered a bounding environment for components exposed to controlled indoor air. The GALL Report states that stainless steel components exposed to uncontrolled indoor air do not have any aging effects, and no AMP is recommended.

In LRA Tables 3.3.2-9, 3.3.2-12, 3.3.2-29, and 3.3.2-30 the applicant stated that for glass piping elements exposed to closed-cycle cooling water (internal) or gas (internal), there is no aging effect, and no AMP is proposed. The AMR items cite generic note G. The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because the GALL Report has multiple AMR Items that state that for an environment of indoor uncontrolled air, raw water, or treated water, there is no AERM and no recommended AMP, and the closed-cycle cooling water (internal) or gas (internal) environment is no more severe than the raw water or indoor uncontrolled air environment already addressed in the GALL Report.

In LRA Tables 3.3.2-9, 3.3.2-17, and 3.3.2-40, the applicant stated that the stainless steel filter element, piping and fittings, valve body, expansion joint, and filter housing exposed to air-outdoor (external) are being managed for loss of material by the External Surfaces Monitoring Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though stainless steel exposed to air-outdoor (external) is not specifically addressed in the GALL Report, Table IX.C of the GALL Report states that stainless steels are susceptible to loss of material due to pitting and crevice corrosion and cracking due to SCC. The staff noted that the environment of interest, air-outdoor (external) would be expected to contain higher levels of chlorides due to the site’s relative proximity to the ocean, which are known to induce SCC. By letter dated February 24, 2011, the staff issued RAI 3.3-1 requesting that the applicant provide additional information on why atmospheric chloride-induced SCC is not considered to be an applicable aging effect for stainless steel components exposed to outdoor-air and explain how SCC will be managed if it is determined to be an applicable aging affect.

In its response dated March 22, 2011, the applicant stated that SCC has been added as an aging mechanism for stainless steel components exposed to air-outdoor environment. The applicant added a new item to manage cracking by either the External Surfaces Monitoring Program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff finds the applicant’s response acceptable because the applicant has modified the LRA to do the following:

- include SCC as an applicable aging effect for stainless steel components exposed to outdoor-air containing high levels of chloride
- include either magnified visual inspection or ultrasonic inspection in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program
- include SCC as an aging effect to be managed by the External Surfaces Monitoring Program, which includes visual inspections that is a capable technique to detect SCC

The staff's concern described in RAI 3.3-1 is resolved.

The staff's evaluations of the applicant's External Surfaces Monitoring Program and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program are documented in SER Sections 3.0.3.2.14 and 3.0.3.2.15, respectively. The staff finds that the applicant's proposal to manage aging using the External Surfaces Monitoring Program and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the programs use periodic or opportunistic visual inspections that would detect loss of material and SCC prior to loss of component-intended function.

In LRA Table 3.3.2-9, the applicant stated that the elastomer flexible connectors exposed to air-indoor controlled (external) are being managed for hardening and loss of strength and loss of material by the External Surfaces Monitoring Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. The GALL Report, item VII.F1-7, states that elastomers exposed to indoor air are susceptible to hardening and loss of strength due to elastomer degradation, and GALL item VII.F1-5 states that elastomers exposed to indoor air are susceptible to loss of material due to wear, both of which are addressed in the AMR items.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff noted that the applicant's program includes non-visual examinations, such as scratching, to determine if scale or residues are present or determine if there is a breakdown of material, bending, or folding of the elastomer to detect cracking that initiates at the surface. The program also includes stretching and pressing to determine the resistance of the material to hardening effects and pressing to gauge the materials resiliency to maintain its strength. The staff finds that the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the program uses periodic visual inspections as well as non-visual tactile examinations, which are capable of detecting loss of material and hardness and loss of strength.

In LRA Table 3.3.2-9, the applicant stated that aluminum heat exchanger components exposed to condensation (external) are being managed for reduction in heat transfer by the External Surfaces Monitoring Program. The AMR item cites generic note F.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effect for this component, material, and environment combination. The GALL Report, item VII.F1-14, states that aluminum components exposed to condensation are susceptible to loss of material, which is addressed in another AMR item. Additionally, the components of interest function in a capacity to provide heat transfer and therefore any accumulation of dirt, debris, or scale could prevent the component from performing its intended function, which is addressed in this AMR item.

In LRA Tables 3.3.2-9 and 3.3.2-12, the applicant stated that aluminum heat exchanger components exposed to air-indoor uncontrolled (external) are being managed for reduction in heat transfer by the External Surfaces Monitoring Program. The AMR item cites generic note F.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination for the following reasons:

- The GALL Report, item V.F-2, states that aluminum components exposed to air have no aging effects requiring management.
- The components of interest function in a capacity to provide heat transfer; therefore, any accumulation of dirt, debris, or scale could prevent the component from performing its intended function, which is addressed in this AMR item.

The staff's evaluation of the applicant's Inspection of External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff finds that the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the program uses periodic visual inspections that would identify corrosion discoloration and accumulation of dirt, scale, or debris indicative of fouling and, thus, detect any reduction in heat transfer prior to loss of the component's intended function.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.10 Demineralized Water System—Aging Management Evaluation—LRA Table 3.3.2-10

The staff reviewed LRA Table 3.3.2-10, which summarizes the results of AMR evaluations for the demineralized water system component groups.

The staff's evaluation for stainless steel bolting, exposed to air-indoor and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.11 Dewatering System—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 dewatering system component groups.

The staff's evaluation for stainless steel bolting, exposed to air-indoor and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for glass piping elements, exposed to air-with borated water leakage (external) with no AERM and no recommended AMP citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for polymer piping, piping components, piping elements, and filter housing exposed to raw water environment, with no aging effect and no AMP proposed citing generic note F, is documented in SER Section 3.3.2.3.4.

The staff's evaluation for elastomer flexible connectors and flexible hose exposed to air with borated water leakage (external), which are being managed for hardening and loss of strength by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for polymer (PVC, PVDF, polypropylene, fluoropolymer, polycarbonate, plastic and polyolefin) piping, piping components, piping elements, flexible hose, tanks, and instrument elements exposed to air-indoor uncontrolled (internal or external) and air-indoor controlled external environments, with no aging effect and no AMP proposed citing generic note F, is documented in SER Section 3.3.2.3.4.

In LRA Tables 3.3.2-11, 3.3.2-20, and 3.3.2-35, the applicant stated that for polymer (PVC, polypropylene, fluoropolymer, polycarbonate, polyolefin, and plastic) piping, piping components and piping elements, tank, and flexible hose exposed to air with borated water external environment, there is no aging effect, and no AMP is proposed. The AMR items cite generic note F. These items also cite plant-specific notes 1 or 2. Plant-specific note 2 states the following:

> Unlike metals, polymers do not display corrosion rates. Rather than depending on an oxide layer for protection, they depend on chemical resistance to the environment to which they are exposed. The plastic is either completely resistant to the environment or it deteriorates. Therefore, acceptability for the use of polymers within a given environment is a design driven criterion. Once the appropriate material is chosen, the system will have no aging effects. This is consistent with plant operating experience.

The staff noted that, as identified in *Engineering Materials Handbook—Engineering Plastics*, American Society for Metals International, Copyright 1988, rigid polymers are unaffected by water, concentrated alkalis, non-oxidizing acids, oils, ozone, sunlight, or humidity changes. The staff also noted that, unlike metals, thermoplastics do not display corrosion rates, and rather than depend on an oxide layer for protection, they depend on chemical resistance to the environments to which they are exposed, and the use of thermoplastics in power plant environments is a design-driven criterion. The staff further noted that thermoplastic materials are impervious and, once selected for the environment, will not have any significant age-related degradation. The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because there is no indication in the industry that polymers or thermoplastics exposed to an internal or external indoor air environment have any aging effects requiring management. Additionally, the generally low operating temperatures and historically good chemical resistance data for polymer components, combined with a lack of historically negative operating experience, indicate that polymers are not likely to experience any degradation from the non-aggressive air with borated water environment.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.12 Diesel Generator—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 diesel generator system component groups.

The staff's evaluation for aluminum flame arrestor and piping and fittings exposed to air-outdoor (external), which are being managed for loss of material by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.1.

The staff's evaluation for stainless steel bolting exposed to air-indoor, which is being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for elastomer flexible hoses exposed to fuel oil or lubricating oil (internal), which are being managed for hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and cite generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for glass piping elements exposed to closed-cycle cooling water (internal) or gas (internal), which cite generic note G, is documented in SER Section 3.3.2.3.9.

The staff's evaluation for aluminum heat exchanger components exposed to air-indoor uncontrolled (external), which are being managed for reduction in heat transfer by the External Surfaces Monitoring Program and cite generic note F, is documented in SER Section 3.3.2.3.9.

In LRA Table 3.3.2-12, the applicant stated that the aluminum heat exchanger components (DG-MM-888A and DG-MM-888 after cooler tubes) exposed to condensation (internal) are being managed for reduction of heat transfer by the Compressed Air Monitoring Program. The AMR item cites generic note F.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because even though the GALL Report does not have aluminum heat exchangers exposed to condensation, heat exchangers are known to be susceptible to reduction of heat transfer aging issues.

The staff's evaluation of the applicant's Compressed Air Monitoring Program is documented in SER Section 3.0.3.2.6. The staff finds the applicant's proposal to manage aging using the Compressed Air Monitoring Program acceptable because the Compressed Air Monitoring Program includes visual inspection techniques that are capable of detecting reduction of heat transfer and annual testing to verify that the performance of the system is in accordance with its intended functions.

In LRA Tables 3.3.2-12 and 3.3.2-15, the applicant stated that elastomer flexible hoses exposed to closed-cycle cooling water (internal) are being managed for hardening and loss of strength with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. The GALL Report, Table IX.C, states that elastomers are susceptible to hardening and loss of strength at temperatures over about 95 °F (35 °C) and when exposed to additional aging factors such as ozone, oxidation, and radiation. The staff noted that the environment of interest, closed-cycle cooling water (internal), has the potential of being in the temperature range for elastomer susceptibility to aging; therefore, the aging effect of concern is hardening and loss of strength, which is addressed in the AMR.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable for the following reasons:

- The program includes periodic visual inspections performed during maintenance and surveillance activities that can identify localized discoloration and surface irregularities.
- The program includes non-visual examinations, such as scratching, which will screen for residues and breakdown of the material, and stretching and pressing which will evaluate the material resiliency to determine if hardening and loss of strength is occurring that could result in a loss of the component-intended function.

In LRA Table 3.3.2-12, the applicant stated that the elastomer flexible hose exposed to condensation (internal) is being managed for hardening and loss of strength by the Compressed Air Monitoring Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though elastomer materials exposed to condensation are not in the GALL Report for hardening and loss of strength, GALL Report, Tables IX.C and IX.E, indicate that elastomers are susceptible to hardening and loss of strength. It was unclear to the staff how the applicant will appropriately manage the hardening and loss of strength of the elastomer components because the indications of aging are substantially different from those of steel or stainless steel, which the GALL Report references. By letter dated January 5, 2011, the staff issued RAI 3.3.2.12-1 requesting that the applicant provide details on the additional inspection methods to be used to ensure that the AMP will adequately address potential aging effects of the elastomer materials.

In its response dated February 3, 2011, the applicant stated that the diesel generator air compressors are replaced every 10 years. The applicant stated that during this routine maintenance, the flexible hoses on these compressors will also be replaced. The applicant stated that because the flexible hoses are periodically replaced, they are not subject to an AMR. The applicant also committed under the Compressed Air Monitoring Program to replace the flexible hoses every 10 years and within 10 years of the period of extended operation. This response is acceptable because the applicant committed to replace the flexible hoses under the Compressed Air Monitoring Program, making them subject to replacement, which does not need to be included in the license renewal process under 10 CFR Part 54.21(a)(1)(ii). The staff's concern described in RAI 3.3.2.12-1 is resolved.

In LRA Table 3.3.2-12, the applicant stated that for aluminum filter housings and valve bodies exposed to dried air (internal), there is no aging effect, and no AMP is proposed. The AMR items cite generic note G. Items associated with aluminum piping, fittings, and valves in Tables 3.3.2-12 and 3.3.2-20 cite plant-specific notes, which state aluminum exposed to dried air environment does not have any applicable aging effect and provide an industry reference as a technical basis.

The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because, even though aluminum exposed to dried air is not specifically addressed in the GALL Report, the GALL Report, item V.F.2, states that aluminum piping, components, and elements exposed to uncontrolled indoor air have no aging effects or aging mechanisms. The staff considers dried air to be less aggressive than uncontrolled indoor air since moisture would not be available to cause loss of material due to pitting.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.13 Diesel Generator Air Handling System—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 diesel generator air handling system component groups.

The staff's review did not find any items indicating plant-specific Notes F–J, whereby the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report.

The staff's evaluation of the items with notes A–E is documented in SER Section 3.3.2.1.

3.3.2.3.14 Emergency Feed Water Pump House Air Handling System—Aging Management Evaluation—LRA Table 3.3.2-14

The staff reviewed LRA Table 3.3.2-14, which summarizes the results of AMR evaluations for the emergency feed water pump house air handling system component groups.

The staff's review did not find any items indicating plant-specific Notes F–J, whereby the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report.

The staff's evaluation of the items with notes A–E is documented in SER Section 3.3.2.1.

3.3.2.3.15 Fire Protection System—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 fire protection system component groups.

The staff's evaluation for elastomer flexible hose exposed to fuel oil or lubricating oil (internal), which are being managed for hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and cite generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for elastomer flexible hose exposed to closed-cycle cooling water (internal), which are being managed for hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and cite generic note G, is documented in SER Section 3.3.2.3.12

The staff's evaluation for fiberglass piping and fittings exposed to raw water (internal) with no AERM and no recommended AMP, citing generic note F, is documented in Section 3.3.2.3.4.

In LRA Table 3.3.2-15, the applicant stated that the stainless steel heat exchanger components exposed to steam are being managed for reduction of heat transfer by the Water Chemistry Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though stainless steel exposed to steam, by this specific aging effect, is not specifically addressed in the GALL Report, Chapter V of the GALL Report states that stainless steel heat exchangers are susceptible to reduction of heat transfer in other aqueous environments. In addition, the GALL Report also states that stainless steel exposed to steam can undergo loss of material or cracking, which the applicant has included in other AMR items. However, it was not clear to staff how the Water Chemistry Program alone would ensure that reduction of heat transfer is appropriately managed. Typically, for reduction of heat transfer, a Water Chemistry Program along with an Inspection Program is used to manage this aging effect. By letter dated January 5, 2011, the staff issued RAI 3.3.2.15-1, requesting that the applicant justify how the Water Chemistry Program alone is sufficient to determine that steam generator tubes are not affected by reduction of heat transfer when exposed to reactor coolant.

In its response dated August 11, 2011, the applicant stated that the steam environment listed in LRA Table 3.3.2-15, for FP-E-46 and FP-E-47, is developed from potable water. The applicant stated that because the steam environment listed is potable water converted to steam, it is not subject to the Water Chemistry Program. The applicant further stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is more appropriate and will be used to manage the heat exchanger reduction of heat transfer. The applicant also stated that it has preventive maintenance activities already in place to clean and inspect the external surfaces of the heat exchanger tubes for FP-E-46 and FP-E-47 on a frequency of approximately every 4 years, and these two items changed from a generic Notes C to G. The staff finds the applicant's response acceptable because the applicant modified the LRA to use inspection programs to identify aging in the heat exchanger tubes, which is consistent with the guidance in the GALL Report. The staff's concern described in RAI 3.3.2.15-1 is resolved.

In LRA Table 3.3.2-15, the applicant stated that steel and stainless steel bolting exposed to soil is being managed for loss of preload and loss of material by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though steel and stainless steel bolting exposed to soil are not specifically addressed in the

GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Similarly, a soil environment as indicated in the GALL Report is known to cause loss of material.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload or loss of material of steel and stainless steel bolting exposed to soil in the auxiliary systems, the GALL Report has items for loss of preload and loss of material of bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because Bolting Integrity Program inspects the bolting to verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. Additionally, the Bolting Integrity Program is supplemented by the Buried Piping and Tanks Inspection Program, which will visually inspect for leakage when bolted joints are excavated.

In LRA Table 3.3.2-15, the applicant stated that the steel and stainless steel bolting exposed to soil is being managed for loss of material by the Buried Piping and Tanks Inspection Program. The AMR item cites generic note G.

The staff noted that LRA Table 3.3.2-15 contains an item for the same component with an aging effect of loss of preload. The staff also noted that the "parameters monitored/inspected" program element of GALL Report AMP XI.M18, "Bolting Integrity," states that, "[s]pecifically, bolting for safety-related pressure-retaining components is inspected for leakage, loss of material, cracking, and loss of preload/loss of prestress. Bolting for other pressure-retaining components is inspected for signs of leakage." The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because, in addition to managing loss of material, the applicant is managing the only other aging effect by using the Bolting Integrity Program to manage loss of preload. The staff noted that GALL Report AMP XI.M.18 does not recommend managing cracking for nonsafety-related bolting.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.3.1. The staff finds that the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program is acceptable for the following reasons:

- The program includes preventive actions, such as external coatings and wrappings installed to industry standard practices and backfill that will not damage the bolting or coatings. Some systems are protected by a cathodic protection system.
- Periodic visual inspections will be performed starting 10 years prior to the period of extended operation and extend into both 10-year periods during the period of extended operation to ensure that coatings remain intact or uncoated bolting has not degraded.
- Plant-specific operating experience will be used to inform inspection locations.
- Alternatives to direct visual inspection, such as pressure tests, are capable of detecting degradation of the bolted connection.

In LRA Table 3.3.2-15, the applicant stated that fiberglass piping exposed to soil is being managed for cracking, blistering and change in material properties by the Buried Piping and Tanks Inspection Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Polymeric materials share many of the same aging effects as elastomers, and the applicant's proposed aging effects are the same as those applicable aging effects listed in GALL Report Table IX.F for elastomeric materials. The staff noted the additional aging effects listed in Table IX.F as follows:

- Aging effects of fatigue breakdown would evidence themselves in a similar manner to that of cracking.
- Abrasion from localized poor quality backfill would evidence itself as loss of material.
- If the soil contains chemicals that affect the polymeric material, the aging effect would be evidenced by loss of material.
- Weathering is not applicable in the soil environment.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.3.1. The staff finds that the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program is acceptable for the following reasons:

- The program includes the preventive action of ensuring that the quality of backfill will not damage the piping.
- Periodic visual inspections, including mechanical examination for evidence of changes in material properties, will be performed starting 10 years prior to the period of extended operation and extend into both 10-year periods during the period of extended operation to ensure that the piping has not degraded.
- Plant-specific operating experience will be used to inform inspection locations.
- Alternatives to direct visual inspection such as pressure tests are capable of detecting degradation of the piping.

In LRA Tables 3.3.2-15, 3.3.2-17, 3.3.2-36, 3.3.2-37, and 3.3.2-40, the applicant stated that copper alloy and copper alloy with greater than 15 percent zinc valve body, instrumentation element, nozzle, filter housing, and piping and fittings exposed to air-outdoor (external) and nickel-alloy rupture disc, expansion joint, instrumentation element, orifice, and thermowell exposed to air-outdoor (external) or condensation (external) are being managed for loss of material by the External Surfaces Monitoring Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. The GALL Report, item VII.G-9, states that copper alloys, including copper alloys with greater than 15 percent zinc, exposed to condensation such as what could occur in an outdoor air environment, are susceptible to loss of material, which is addressed in this AMR item. While nickel-alloy components exposed to condensation (external) are not specifically addressed in the GALL Report for item VII.C1-13, it states that nickel alloys exposed to raw water are susceptible to loss of material, which is addressed in the AMR item.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff finds that the applicant's proposal to manage aging using the

External Surfaces Monitoring Program acceptable because the program uses periodic visual inspections that would detect loss of material prior to loss of component-intended function.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.16 Fuel Handling System 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 fuel handling system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, which is being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for glass piping elements exposed to air-with borated water leakage (external), with no AERM and no recommended AMP citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for elastomer flexible connectors and flexible hose exposed to air with borated water leakage (external), which are being managed for hardening and loss of strength by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.3.

In LRA Tables 3.3.2-16 and 3.3.2-35, the applicant stated that elastomer flexible hoses exposed to treated water (internal) are being managed for hardening and loss of strength with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because the GALL Report, Table IX.C, states that elastomers are susceptible to hardening and loss of strength at temperatures over about 95 °F (35 °C) and when exposed to additional aging factors such as ozone, oxidation, and radiation. The staff noted that the environment of interest, treated water (internal) has the potential of being in the temperature range for elastomer susceptibility to aging; therefore, the aging effect of concern is hardening and loss of strength, which is addressed in the AMR.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable for the following reasons:

- The program include periodic visual inspections performed during maintenance and surveillance activities, which can identify localized discoloration and surface irregularities.

- Non-visual examinations, such as scratching, which will screen for residues and breakdown of the material, and stretching and pressing, which will evaluate the material resiliency to determine if hardening and loss of strength are occurring that could result in a loss of the component-intended function.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.17 Fuel Oil System—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 fuel oil system component groups.

The staff's evaluation for steel bolting exposed to air-outdoor, which is being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.1.

The staff's evaluation for stainless steel piping and fittings, valve body, expansion joint, filter housing and tanks exposed to air-outdoor (external), which are being managed for loss of material by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.9.

The staff's evaluation for copper alloy and copper alloy with greater than 15 percent zinc valve body, instrumentation element, nozzle, filter housing, and piping and fittings, and nickel-alloy piping and fittings, valve body, expansion joint, and rupture disc exposed to air-outdoor (external), which are being managed for loss of material by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.15.

In LRA Tables 3.3.2-17 and 3.3.2-40, the applicant stated that the stainless steel bolting exposed to air-outdoor is being managed for loss of material by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though stainless steel bolting exposed to air-outdoor is not specifically addressed in the GALL Report, Table IX.C of the GALL Report states that stainless steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion and cracking due to SCC. The staff noted that given the plant's proximity to the ocean, stainless steel bolting exposed to the outdoor air environment would be susceptible to SCC. However, the staff noted that the applicant did not identify SCC as an AERM for these components. By letter dated February 24, 2011, the staff issued RAI 3.3-1 requesting that the applicant justify its management of this material, environment, AERM, and AMP combination.

In its response dated March 22, 2011, the applicant stated that SCC has been added as an aging mechanism for stainless steel components exposed to air-outdoor environment. The applicant added a new item to manage cracking of bolts by the Bolting Integrity Program. The staff finds the applicant's response acceptable because the applicant modified the LRA to include cracking due to SCC as an applicable aging effect for stainless steel components exposed to outdoor-air containing high levels of chloride and is managing SCC by the Bolting Integrity Program. The staff's concern described in RAI 3.3-1 is resolved.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for stainless steel bolting exposed to air-outdoor in the auxiliary system, the GALL Report has items for other material bolting exposed to air-outdoor managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program inspects the bolting through periodic visual inspections to verify that the aging effect, loss of material and SCC, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation; therefore, it is acceptable.

In LRA Tables 3.3.2-17 and 3.3.2-40, the applicant stated that the stainless steel bolting exposed to air-outdoor is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though stainless steel bolting exposed to air-outdoor is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, Table IX.C of the GALL Report states that stainless steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion and cracking due to SCC. The staff noted that the applicant addressed loss of material in additional items for each of these components and the staff evaluated SCC as documented in SER Section 3.3.2.3.17 for this component, material, and environment combination; therefore, the aging effect of concern is loss of preload, which is addressed in the AMR

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload of stainless steel bolting exposed to air-outdoor in the auxiliary system, the GALL Report has items for other material bolting exposed to air-outdoor managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload. The program also inspects for leakage and loose or missing nuts which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.18 Fuel Storage Building Air Handling System—Aging Management Evaluation—LRA Table 3.3.2-18

The staff reviewed LRA Table 3.3.2-18, which summarizes the results of AMR evaluations for the fuel storage building air handling system component groups.

The staff's evaluation for elastomer flexible connectors and flexible hose exposed to air with borated water leakage (external), which are being managed for hardening and loss of strength by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for elastomer flexible connectors exposed to air with borated water leakage (external), which are being managed for loss of material by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.5.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.19 Hot Water Heating System—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 hot water heating system component groups.

The staff's evaluation for stainless steel bolting, exposed to air-indoor and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

In LRA Tables 3.3.2-19, and 3.3.2-44, the applicant stated that the steel bolting exposed to air-indoor uncontrolled (external) is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though steel bolting exposed to air-indoor uncontrolled is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, Table IX.C of the GALL Report states that steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to general, pitting and crevice corrosion. The staff noted that the applicant addressed loss of material in additional items for each of these components; therefore, the aging effect of concern is loss of preload, which is addressed in the AMR.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload of steel bolting exposed to condensation in the auxiliary system, the GALL Report has items for loss of preload of other material bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload. The program also inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff's evaluation for glass piping elements exposed to air-with borated water leakage (external), with no AERM and no recommended AMP citing generic note G, is documented in SER Section 3.3.2.3.3.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.20 Instrument Air System—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 instrument air system component groups.

The staff's evaluation for stainless steel bolting, exposed to air-indoor and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for elastomer flexible connectors and flexible hose exposed to air with borated water leakage (external), which are being managed for hardening and loss of strength by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for polymer (PVC, PVDF, polypropylene, fluoropolymer, polycarbonate, plastic, and polyolefin) piping, piping components, and piping elements, flexible hose, tanks, and instrument elements, exposed to air-indoor uncontrolled (internal or external) and air-indoor controlled external environments with no aging effect and no AMP proposed citing generic note F, is documented in SER Section 3.3.2.3.4.

The staff's evaluation for polymer (PVC, polypropylene, fluoropolymer, polycarbonate, polyolefin, and plastic) piping, piping components and piping elements, tank and flexible hose exposed to air with borated water external environment, with no aging effect and no AMP proposed citing generic note F, is documented in SER Section 3.3.2.3.11.

The staff's evaluation for aluminum filter housings, instrumentation elements, and valve bodies exposed to dried air, which cite generic note G, is documented in Section 3.3.2.3.12.

In LRA Table 3.3.2-20, the applicant stated that the aluminum heat exchanger components exposed to lubricating oil (internal) are being managed for loss of material by the Lubricating Oil Analysis Program, as augmented by the One-Time Inspection Program. The AMR item cites generic note F.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because, as stated in the *ASM Handbook*, ASM International, 2005, aluminum is a corrosion-resistant material. For aluminum heat exchanger components used in heat exchanger shells and tubes internally exposed to oil, the applicant identified the appropriate aging effect (i.e., loss of material). This aging effect is managed by the Lubricating Oil Analysis Program and is augmented by the One-Time Inspection Program. The staff's evaluation of the applicant's Lubricating Oil Analysis Program and One-Time Inspection Program is documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. The Lubricating Oil Analysis Program performs oil condition monitoring activities to manage the aging effects of loss of material due to galvanic, general, pitting, crevice, and MIC and fouling and heat transfer degradation due to fouling. The One-Time Inspection Program performs a one-time inspection of selected components containing lubricating oil determined to be most susceptible to the potential degradation mechanisms to verify the effectiveness of the Lubricating Oil Analysis Program.

The staff finds the applicant's proposal to manage aging using the Lubricating Oil Analysis Program, as augmented by the One-Time Inspection Program, acceptable because the Lubricating Oil Analysis Program monitors for contaminants that could cause corrosion and for degradation of the oil, which could be caused by corrosion products. This analysis is supplemented by the One-Time Inspection Program, which uses visual examination and other examination techniques to inspect for the loss of material in areas where the most severe aging effects would be expected to occur.

In LRA Tables 3.3.2-20 and 3.3.2-23, the applicant stated that the aluminum valve body and pump casing components exposed to lubricating oil (internal) are being managed for loss of material by the Lubricating Oil Analysis Program, as augmented by the One-Time Inspection Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material and environment combination. As stated in the *ASM Handbook*, ASM International, 2005, aluminum is a corrosion-resistant material, and for aluminum valve body and pump casing components internally exposed to oil, the applicant identified the appropriate aging effects (i.e., loss of material). This aging effect is managed by the Lubricating Oil Analysis Program and is augmented by the One-Time Inspection Program. The staff's evaluations of the applicant's Lubricating Oil Analysis Program and the One-Time Inspection Program are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. The Lubricating Oil Analysis Program performs oil condition monitoring activities to manage the aging effects of loss of material due to galvanic, general, pitting, crevice, and MIC and fouling and heat transfer degradation due to fouling. The One-Time Inspection Program performs a one-time inspection of selected components containing lubricating oil determined to be most susceptible to the potential degradation mechanisms to verify the effectiveness of the Lubricating Oil Analysis Program

The staff finds the applicant's proposal to manage aging using the Lubricating Oil Analysis Program, as augmented by the One-Time Inspection Program, acceptable because the Lubricating Oil Analysis Program monitors for contaminants that could cause corrosion and for degradation of the oil, which could be caused by corrosion products. This analysis is supplemented by the One-Time Inspection Program, which uses visual examination and other examination techniques to inspect for the loss of material in areas where the most severe aging effects would be expected to occur.

In LRA Table 3.3.2-20, the applicant stated that for polymer (CPVC and fluoropolymer) piping and fittings, and flexible hose exposed to dried air internal environment, there is no aging effect, and no AMP is proposed. The AMR items cite generic note F. These items also cite plant-specific note 2, which states the following:

> Unlike metals, polymers do not display corrosion rates. Rather than depending on an oxide layer for protection, they depend on chemical resistance to the environment to which they are exposed. The plastic is either completely resistant to the environment or it deteriorates. Therefore, acceptability for the use of polymers within a given environment is a design driven criterion. Once the appropriate material is chosen, the system will have no aging effects. This is consistent with plant operating experience.

The staff noted that, as identified in *Engineering Materials Handbook—Engineering Plastics*, American Society for Metals International, Copyright 1988, rigid polymers are unaffected by water, concentrated alkalis, non-oxidizing acids, oils, ozone, sunlight, or humidity changes. The staff also noted that, unlike metals, thermoplastics do not display corrosion rates, and rather than depend on an oxide layer for protection, they depend on chemical resistance to the environments to which they are exposed and the use of thermoplastics in power plant environments is a design-driven criterion. The staff further noted that thermoplastic material is impervious and, once selected for the environment, will not have any significant age-related degradation. The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because there is no indication in the industry that polymers or thermoplastics exposed to an internal or external indoor air environment have any aging effects requiring management. Additionally, the generally low operating temperatures and historically good chemical resistance data for polymer components, combined with a lack of historically negative operating experience, indicate that polymers are not likely to experience any degradation from the non-aggressive dried air environment.

In LRA Tables 3.3.2-20 and 3.3.2-23, the applicant stated that the aluminum components exposed to lubricating oil are being managed for loss of material by the Lubricating Oil Analysis and One-Time Inspection Programs. The AMR item associated with Table 3.3.2-20 cite generic note F, and AMR items associated with Tables 3.3.2-23, 3.4.2-6, and 3.4.2-7 cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because loss of material may occur due to pitting and crevice corrosion of the aluminum components exposed to lubricating oil in the heat exchanger, valve body, pump casing, and instrumentation elements.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection Programs are documented in SER Section 3.0.3.2.16 and 3.0.3.1.8, respectively. The staff finds the applicant's proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection Programs acceptable because the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report. Additionally, the applicant stated that the One-Time Inspection Program will be used to examine aluminum components and elements to verify the effectiveness of the Lubricating Oil Analysis Program.

In LRA Table 3.3.2-20, the applicant stated that elastomer flexible hoses exposed to condensation or dried air (internal) are being managed for hardening and loss of strength with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR item cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. The GALL

Report, Table IX.C, states that elastomers are susceptible to hardening and loss of strength at temperatures over about 95 °F (35 °C) and when exposed to additional aging factors such as ozone, oxidation, and radiation. The staff noted that the environment of interest, condensation (internal), has the potential of being in the temperature range for elastomer susceptibility to aging; therefore, the aging effect of concern is hardening and loss of strength, which is addressed in the AMR.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable for the following reasons:

- The program includes periodic visual inspections performed during maintenance and surveillance activities, which can identify localized discoloration and surface irregularities.
- Non-visual examinations, such as scratching, which will screen for residues and breakdown of the material, and stretching and pressing, which will evaluate the material resiliency to determine if hardening and loss of strength are occurring that could result in a loss of the component-intended function.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR result of material, environment, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.21 Leak Detection System—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 leak detection system component groups.

The staff's evaluation for stainless steel bolting, exposed to air-indoor and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.22 Mechanical Seal Supply System—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 mechanical seal supply system component groups.

The staff's evaluation for stainless steel bolting, exposed to air-indoor and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.23 Miscellaneous Equipment System—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 miscellaneous equipment system component groups.

The staff's evaluation for elastomer flexible hose exposed to fuel oil or lubricating oil (internal), which are being managed for hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and cite generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for aluminum pump casing components, exposed to lubricating oil (internal) and being managed for loss of material by the Lubricating Oil Analysis and One-Time Inspection Programs citing generic note G, is documented in SER Section 3.3.2.3.20.

The staff's evaluation for elastomer flexible connectors and flexible hose exposed to air with borated water leakage (external), which are being managed for hardening and loss of strength by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for aluminum components, exposed to lubricating oil are being managed for loss of material by the by the Lubricating Oil Analysis Program and the One-Time Inspection Program citing generic note G, is documented in SER Section 3.3.2.3.20.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.24 Nitrogen Gas System—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 nitrogen gas system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, which is being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.25 Oil Collection for Reactor Coolant Pumps System—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 oil collection for reactor coolant pumps system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, which is being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.26 Plant Floor Drain System—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 plant floor drain system component groups.

The staff's evaluation for polymer (PVC, PVDF, polypropylene, fluoropolymer, polycarbonate, plastic, and polyolefin) piping, piping components, and piping elements, flexible hose, tanks, and instrument elements exposed to air-indoor uncontrolled (internal or external) and air-indoor controlled external environments, with no aging effect and no AMP proposed citing generic note F, is documented in SER Section 3.3.2.3.4.

The staff's evaluation for polymer piping, piping components and piping elements, and filter housing exposed to raw water environment, with no aging effect and no AMP proposed citing generic note F, is documented in SER Section 3.3.2.3.4.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.27 Potable Water System—Aging Management Evaluation—LRA Table 3.3.2-27

The staff reviewed LRA Table 3.3.2-27, which summarizes the results of AMR evaluations for the potable water system component groups.

The staff's review did not find any items indicating plant-specific Notes F–J, whereby the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report.

The staff's evaluation of the items with notes A–E is documented in SER Section 3.3.2.1.

3.3.2.3.28 Primary Auxiliary Building Air Handling System—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 primary auxiliary building air handling system component groups.

The staff's evaluation for elastomer flexible connectors and flexible hose exposed to air with borated water leakage (external), which are being managed for hardening and loss of strength by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for elastomer flexible connectors exposed to air with borated water leakage (external), which are being managed for loss of material by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.5.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.29 Primary Component Cooling Water System—Aging Management Evaluation—LRA Table 3.3.2-29

The staff reviewed LRA Table 3.3.2-29, which summarizes the results of AMR evaluations for the primary component cooling water system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, which is being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for nickel-alloy components exposed borated water leakage that is not subject to an aging effect requiring management, with generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for glass piping elements exposed to air-with borated water leakage (external), with no AERM and no recommended AMP citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for glass piping elements exposed to closed-cycle cooling water (internal) or gas (internal), which cite generic note G, is documented in SER Section 3.3.2.3.9.

In LRA Table 3.3.2-29, the applicant stated that the nickel-alloy flexible hoses and valve bodies exposed to closed-cycle cooling water are being managed for loss of material by the Closed-Cycle Cooling Water System Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA in order to confirm that the applicant identified the correct aging effect(s) for this component, material, and environment combination. The staff noted that GALL Table IX.F states that nickel based alloy components are susceptible to crevice corrosion and that high temperatures are required for nickel alloys to be susceptible to certain types of SCC. The staff confirmed the applicant identified the correct aging effect because, as noted in the GALL Report, nickel-alloy components are susceptible to loss of material, and the maximum temperature in the primary component cooling water system is less than 140 °F and is not high enough to cause SCC for this material.

The staff's evaluation of the applicant's Closed-Cycle Cooling Water Program is documented in SER Section 3.0.3.2.4. The staff noted that the Closed-Cycle Cooling Water Program consists of visual inspections, chemistry control, and monitoring of corrosion coupons. The staff finds the applicant's proposal to manage aging using the Closed-Cycle Cooling Water Program acceptable for the following reasons:

- The applicant will conduct visual inspections that are capable of identifying loss of material.
- The applicant is using chemistry control techniques that will minimize the susceptibility to corrosion.
- The applicant will monitor corrosion coupons that will provide an indication of corrosion in the closed-cycle cooling water systems.

In LRA Table 3.3.2-29, the applicant stated that the titanium heat exchanger components exposed to closed-cycle cooling water and raw water are being managed for reduction of heat transfer by the Closed-Cycle Cooling Water System and Open-Cycle Cooling Water System Programs. The AMR items cite generic note F.

The staff reviewed the associated items in the LRA in order to confirm that the applicant identified the correct aging effects for this component, material, and environment combination. The staff finds consideration of reduction in heat transfer for titanium heat exchanger components exposed to closed-cycle cooling or raw water environments to be appropriate because the GALL Report includes this aging effect for all other heat exchanger component materials in these environments. However, titanium is known to be susceptible to cracking in certain environments depending upon the type of titanium, and it can also undergo loss of material due to crevice corrosion at certain chloride levels and temperatures. The applicant did not address cracking or loss of material as relevant aging effects for the titanium alloy heat exchanger tubes. By letter dated January 5, 2011, the staff issued RAI 3.3.2.3.29-1 asking the applicant to justify why cracking and loss of material had not been considered as relevant aging effects for the titanium alloy heat exchanger tubes.

In its response dated February 3, 2011, the applicant stated that the titanium components within the scope of license renewal are titanium Grade 1 or Grade 2. The applicant also stated that although the maximum design temperature for the heat exchangers is 200 °F (93 °C), the normal operating temperature is well below 160 °F (71 °C). The applicant cited statements in Revision 2 of the GALL Report, which indicate that unalloyed titanium (including Grade 1 and Grade 2) are not susceptible to SCC in seawater or brackish raw water but may be susceptible to crevice corrosion in saltwater environments at elevated temperature greater than 160 °F (71 °C). The applicant also cited statements in the EPRI Report, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools," which indicate that titanium alloys exhibit negligible corrosion rates in seawater for temperatures as high as 500 °F (260 °C) and that crevice corrosion requires significant amounts of chloride. The applicant further stated that operating experience did not indicate any cracking or loss of material during the 14 years these components have been in service. The staff finds the applicant's justification acceptable because loss of material or SCC would not be expected for the grades of titanium being used in the environmental conditions with normal operating temperatures less than 160 °F (71 °C). The staff's concern described in RAI 3.3.2.3.29-1 is resolved. The staff confirmed that the applicant identified the correct aging effects for this component, material, and environment combination for the associated items in the LRA because loss of material and cracking should not occur, based on the above RAI response.

The staff's evaluations of the applicant's Closed-Cycle Cooling Water System and Open-Cycle Cooling Water System Programs are documented in SER Sections 3.0.3.2.4 and 3.0.3.2.3, respectively. The staff finds the applicant's proposal to manage aging using the referenced programs acceptable because the Closed-Cycle Cooling Water and Open-Cycle Cooling Water Programs verify that reduction in heat transfer does not occur through internal inspections of opportunity or through periodic performance testing.

In LRA Table 3.3.2-29, the applicant stated that, for the titanium heat exchanger components (channel head) and piping and fittings exposed externally to uncontrolled indoor air, there is no aging effect, and no AMP is proposed. The AMR item cite generic note F. Items associated with heat exchanger components (channel head) and piping and fittings in LRA Table 3.3.2-29 cite plant-specific note 3, which states that titanium material has superior resistance to general, pitting, crevice, and MIC in both air and water environments due to a protective oxide film. The applicant also stated that this is consistent with plant operating experience.

The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because of the excellent corrosion resistance that titanium exhibits in air, oxidizing, and aqueous conditions. This is supported by information in the *Metals Handbook* (Reference 1) and the *Metals Properties Handbook: Titanium Alloys* (Reference 2). Titanium and its alloys are fully resistant to general corrosion and pitting in water, natural waters and steam to 600 °F (315 °C). In addition, multiple references (References 3, 4, and 5) state that titanium is resistant to pitting, general, and crevice corrosion and SCC in turbine exhaust steam environments in essence due to its formation of very stable, continuous, highly adherent, and protective oxide films on metal surfaces. In addition, the staff also notes that, due to its corrosion resistance capabilities, titanium is widely used in the refinery industry for condenser tubing and the aerospace industry in temperature applications up to 1,112 °F (600 °C). Based on these references and industry applications, the staff finds the applicant's proposal, that there are no other AERMs, acceptable based on titanium's resistance to pitting, general, and crevice corrosion and SCC in air and aqueous systems.

In LRA Table 3.3.2-29, the applicant stated that for titanium heat exchanger components (channel head) and piping and fittings exposed to air with borated water leakage, there is no aging effect, and no AMP is proposed. The AMR item cite generic note F.

The staff reviewed the associated items in the LRA and noted that the components of interest, heat exchanger components and piping and fittings, may be in a temperature regime that would make it susceptible to crevice attack. In addition, the environment, air with borated water leakage, may—along with higher temperatures—place the titanium alloy material in a condition where it would be susceptible to SCC. By letter dated January 5, 2011, the staff issued RAI 3.3.2.3.29-1 requesting that the applicant justify the exclusion of the crevice corrosion and SCC aging effects. If the crevice corrosion and SCC aging effects need to be considered during the period of extended operation, the staff asked the applicant to describe the AMP that will manage the aging effects.

In its response dated February 3, 2011, the applicant stated that the tubes and all tube-side wetted components and surfaces are titanium Grade 2, except for the tubesheet and channel head cover, which are steel clad with titanium Grade 1. The small-bore piping is also titanium

Grade 2. Grade 1 and Grade 2 titanium are unalloyed titanium. The applicant also stated that the maximum design temperature for the heat exchangers is 200 °F; however, normal operating temperatures are well below 160 °F (heat exchanger inlet and outlet temperatures are less than 70 °F with the plant at 100 percent power) for the shell side (closed-cycle cooling water) materials and less than 65 °F for the tube side (raw water and seawater) materials. During RFOs, with RHR in service, heat exchanger inlet and outlet temperatures are less than 100 °F. The applicant further quoted EPRI Mechanical Tools (Reference 6), which states the following:

> [T]itanium and titanium alloys are also susceptible to crevice corrosion although it requires significant aqueous chloride contamination (> 1000 ppm) at elevated temperatures (> 160 °F) to be subject to this attack. Grades 1, 2, 7, 11 and 12 of titanium and its alloys are virtually immune to SCC except in a few specific environments (such as anhydrous methanol/halide solutions, red fuming nitric acid (HNO_3) and liquid cadmium), none of which are applicable in raw water systems.

The applicant concluded by stating that these titanium components have been in service for approximately 14 years, with no indications of cracking or loss of material.

The staff finds the applicant’s response acceptable because the staff noted that titanium alloys are resistant to water, seawater, and boric acid (Reference 4). In addition, the current staff position is that titanium and titanium alloys may be susceptible to crevice corrosion in saltwater environments at elevated temperatures (greater than 160 °F), and ASTM Grades 1, 2, 7, 11, or 12 are not susceptible to SCC in seawater or brackish raw water. The staff further noted that the operating temperatures of the applicant’s titanium components are well below 160 °F. In addition, the staff noted that applicant’s titanium components are either Grade 1 or 2 material, which is susceptible to SCC only in a few specific cases; however, these conditions are not found in the applicant’s operating environment. The staff further noted the applicant’s operating experience confirmed that there has not been loss of material since the equipment entered service. Therefore, the staff’s concern described in RAI 3.3.2.3.29-1 is resolved.

In LRA Table 3.3.2-29, the applicant stated that for the titanium and steel with titanium cladding heat exchanger components (channel head, head cover, and tubesheet) and piping and fittings exposed internally to raw water, there is no aging effect, and no AMP is proposed. The AMR item cites generic note F. Items associated with heat exchanger components (channel head, head cover, and tubesheet) and piping and fittings in Table 3.3.2-29 cite plant-specific note 3, which states that titanium material has superior resistance to general, pitting, crevice, and MIC in both air and water environments due to a protective oxide film. The applicant also indicated that this was consistent with plant operating experience.

The staff reviewed the associated items in the LRA and noted that, in LRA Table 3.0-1, the applicant defined raw water as raw, untreated fresh, salt, potable, or groundwater. The staff noted that although titanium has excellent corrosion resistance in air, oxidizing, and aqueous conditions, certain alloys of titanium can exhibit crevice corrosion and SCC in seawater at temperatures greater than 167 °F (75 °C) (Reference 7). The components of interest, heat exchanger components and piping and fittings, may be in a temperature regime that would make it susceptible to crevice attack. In addition, the environment, raw water, may—along with higher temperatures—place the titanium alloy material in a condition where it would be susceptible to SCC. By letter dated January 5, 2011, the staff issued RAI 3.3.2.3.29-1 requesting that the applicant justify the exclusion of the crevice corrosion and SCC aging effects. Additionally, if the crevice corrosion and SCC aging effects need to be considered during the period of extended operation, the staff asked the applicant to describe the AMP that will manage the aging effects.

In its response dated February 3, 2011, the applicant stated that the tubes and all tube side wetted components and surfaces are titanium Grade 2, except for the tubesheet and channel head cover, which are steel clad with titanium Grade 1. The small-bore piping is also titanium Grade 2. Grade 1 and Grade 2 titanium are unalloyed titanium. The applicant also stated that the maximum design temperature for the heat exchangers is 200 °F; however, normal operating temperatures are well below 160 °F (heat exchanger inlet and outlet temperatures are less than 70 °F with the plant at 100 percent power) for the shell side (closed-cycle cooling water) materials and less than 65 °F for the tube side (raw water and seawater) materials. During RFOs, with RHR in service, heat exchanger inlet and outlet temperatures are less than 100 °F. The applicant further quoted EPRI Mechanical Tools (Reference 6), which states the following:

> [T]itanium and titanium alloys are also susceptible to crevice corrosion although it requires significant aqueous chloride contamination (> 1000 ppm) at elevated temperatures (> 160 °F) to be subject to this attack. Grades 1, 2, 7, 11 and 12 of titanium and its alloys are virtually immune to SCC except in a few specific environments (such as anhydrous methanol/halide solutions, red fuming nitric acid (HNO_3) and liquid cadmium), none of which are applicable in raw water systems.

The applicant concluded by stating that these titanium components have been in service for approximately 14 years, with no indications of cracking or loss of material.

The staff finds the applicant’s response acceptable because the operating temperatures of the applicant’s titanium components were well below 160 °F, a temperature above which crevice corrosion could be an issue. In addition, the current staff position is that titanium and titanium alloys may be susceptible to crevice corrosion in saltwater environments at elevated temperatures (greater than 160 °F), and ASTM Grades 1, 2, 7, 11, or 12 are not susceptible to SCC in seawater or brackish raw water. In addition, the staff noted that applicant’s titanium components are either Grade 1 or 2 material, which is susceptible to SCC in a few specific cases; however, these conditions are not found in the applicant’s operating environment. The staff further noted the applicant’s operating experience confirmed that there has not been loss of material since the equipment entered service. Therefore, the staff’s concern described in RAI 3.3.2.3.29-1 is resolved.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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 Radiation Monitoring System—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 radiation monitoring system component groups.

The staff’s evaluation for stainless steel bolting exposed to air-indoor, which is being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for glass piping elements exposed to air-with borated water leakage (external), with no AERM and no recommended AMP citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for glass piping elements exposed to closed-cycle cooling water (internal) or gas (internal), which cite generic note G, is documented in SER Section 3.3.2.3.9.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.31 Reactor Makeup Water System—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 reactor makeup water system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for glass piping elements exposed to air-with borated water leakage (external), with no AERM and no recommended AMP citing generic note G, is documented in SER Section 3.3.2.3.3.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.32 Release Recovery System—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 release recovery system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.33 Resin Sluicing System—Aging Management Evaluation—LRA Table 3.3.2-33

The staff reviewed LRA Table 3.3.2-33, which summarizes the results of AMR evaluations for the resin sluicing system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.34 Roof Drains System—Aging Management Evaluation—LRA Table 3.3.2-34

The staff reviewed LRA Table 3.3.2-34, which summarizes the results of AMR evaluations for the roof drains system component groups.

The staff's review did not find any items indicating plant-specific Notes F–J, whereby the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report.

The staff's evaluation of the items with notes A–E is documented in SER Section 3.3.2.1.

3.3.2.3.35 Sample System—Aging Management Evaluation—LRA Table 3.3.2-35

The staff reviewed LRA Table 3.3.2-35, which summarizes the results of AMR evaluations for the sample system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for glass piping elements exposed to air-with borated water leakage (external), with no AERM and no recommended AMP citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for polymer (PVC, PVDF, polypropylene, fluoropolymer, polycarbonate, plastic, and polyolefin) piping, piping components, and piping elements, flexible hose, tanks, and instrument elements exposed to air-indoor uncontrolled (internal or external) and air-indoor controlled external environments, with no aging effect and no AMP proposed citing generic note F, is documented in SER Section 3.3.2.3.4.

The staff's evaluation for polymer (PVC, polypropylene, fluoropolymer, polycarbonate, polyolefin, and plastic) piping, piping components and piping elements, tank and flexible hose exposed to air with borated water external environment, with no aging effect and no AMP proposed citing generic note F, is documented in SER Section 3.3.2.3.11.

In LRA Table 3.3.2-35, the applicant stated that for polymer (polycarbonate, plastic, polyolefin) instrumentation element and traps exposed to treated water or treated borated water internal environment, there is no aging effect, and no AMP is proposed. The AMR items cite generic note F. These items also cite plant-specific note 1, which states the following:

> Unlike metals, polymers do not display corrosion rates. Rather than depending on an oxide layer for protection, they depend on chemical resistance to the

> environment to which they are exposed. The plastic is either completely resistant to the environment or it deteriorates. Therefore, acceptability for the use of polymers within a given environment is a design driven criterion. Once the appropriate material is chosen, the system will have no aging effects. This is consistent with plant operating experience.

The staff noted that, as identified in *Engineering Materials Handbook—Engineering Plastics*, American Society for Metals International, Copyright 1988, rigid polymers are unaffected by water, concentrated alkalis, non-oxidizing acids, oils, ozone, sunlight, or humidity changes. The staff also noted that, unlike metals, thermoplastics do not display corrosion rates, and rather than depend on an oxide layer for protection, they depend on chemical resistance to the environments to which they are exposed and the use of thermoplastics in power plant environments is a design-driven criterion. The staff further noted that thermoplastic material is impervious and, once selected for the environment, will not have any significant age-related degradation. The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination because there is no indication in the industry that polymers or thermoplastics exposed to an internal or external indoor air environment have any aging effects requiring management. Additionally, the generally low operating temperatures and historically good chemical resistance data for polymer components, combined with a lack of historically negative operating experience, indicate that polymers are not likely to experience any degradation from the non-aggressive treated water or treated borated water environment.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR result of material, environment, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.36 Screen Wash System—Aging Management Evaluation—LRA Table 3.3.2-36

The staff reviewed LRA Table 3.3.2-36, which summarizes the results of AMR evaluations for the screen wash system component groups.

The staff's evaluation for steel bolting exposed to condensation, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.19.

The staff's evaluation for nickel alloy exposed to condensation, being managed for loss of material by the External Surfaces Program citing generic note G, is documented in SER Section 3.3.2.3.15.

The staff's evaluation for fiberglass filter housings exposed to condensation (external) or raw water (internal) with no AERM and no recommended AMP, citing generic note F, is documented in Section 3.3.2.3.4.

In LRA Table 3.3.2-36, the applicant stated that the stainless steel bolting exposed to condensation is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though stainless steel bolting exposed to condensation is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, Table IX.C of the GALL Report states that stainless steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion and cracking due to SCC. The staff noted that the environment of interest, condensation would not induce SCC in stainless steel material because stainless steel is inherently resistant to SCC in a condensation environment and becomes susceptible to SCC only at temperatures above 140 °F (60 °C). The staff noted that the applicant addressed loss of material in additional items for each of these components; therefore, the aging effect of concern is loss of preload, which is addressed in the AMR.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload of stainless steel bolting exposed to condensation in the auxiliary system, the GALL Report has items for loss of preload of other material bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload. Additionally, the program inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.37 Service Water System—Aging Management Evaluation—LRA Table 3.3.2-37

The staff reviewed LRA Table 3.3.2-37, which summarizes the results of AMR evaluations for the service water system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for nickel-alloy components exposed borated water leakage that is not subject to an aging effect requiring management, with generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for glass piping elements exposed to air-with borated water leakage (external), with no AERM and no recommended AMP citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for polymer piping, piping components and piping elements, and filter housing exposed to raw water environment, with no aging effect and no AMP proposed citing generic note F, is documented in SER Section 3.3.2.3.4.

The staff's evaluation for polymer (PVC) piping and fittings and filter housing exposed to condensation (internal or external) environment, with no aging effect and no AMP proposed citing generic note F, is documented in SER Section 3.3.2.3.4.

The staff's evaluation for copper alloy and copper alloy with greater than 15 percent zinc valve body, instrumentation element, nozzle, filter housing, and piping and fittings, and nickel-alloy piping and fittings, valve body, expansion joint, and rupture disc exposed to air-outdoor (external), which are being managed for loss of material by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.15.

In LRA Table 3.3.2-37, the applicant stated that the stainless steel bolting exposed to raw water is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material and environment combination. Even though stainless steel bolting exposed to raw water is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, Table IX.C of the GALL Report states that stainless steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion, MIC, and cracking due to SCC. The staff noted that the environment of interest, raw water, would not induce SCC in stainless steel material because stainless steel becomes susceptible to corrosion in the raw water environment only at temperatures above 140 °F (60 °C). The staff noted that the applicant addressed loss of material in additional items for each of these components; therefore, the aging effect of concern is loss of preload, which is addressed in the AMR

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload of stainless steel bolting exposed to raw water in the auxiliary system, the GALL Report has items for loss of preload of other material bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload. The program also inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

In LRA Table 3.3.2-37, the applicant stated that steel bolting exposed to raw water is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though steel bolting exposed to raw water is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, Table IX.C of the GALL Report states that steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to general, pitting, and crevice corrosion. The staff noted that the applicant addressed loss of material in additional items for each of these components; therefore, the aging effect of concern is loss of preload, which is addressed in the AMR.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload of steel bolting exposed to raw water in the auxiliary system, the GALL Report has items for loss of preload of other material bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload. The program also inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

In LRA Table 3.3.2-37, the applicant stated that the elastomer expansion joint exposed to condensation (external) are being managed for hardening and loss of strength by the External Surfaces Monitoring Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. The GALL Report, Table IX.C, indicates that elastomers are susceptible to hardening and loss of strength at temperatures over 95 °F (35 °C), and the environment of interest, condensation, can be in a temperature range where the elastomer is susceptible to hardening and loss of strength.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff noted that the applicant's program includes non-visual examinations, such as scratching, to determine if scale or residues are present or determine if there is a breakdown of material. The program includes bending or folding of the elastomer to detect cracking that initiates at the surface, stretching and pressing to determine the resistance of the material to hardening effects, and pressing to gauge the materials resiliency. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the program uses periodic visual inspections as well as non-visual tactile examinations, which are capable of detecting hardening and loss of strength.

In LRA Table 3.3.2-37, the applicant stated that copper-alloy (greater than 15 percent zinc) bolting exposed to raw water is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though copper-alloy (greater than 15 percent zinc) bolting exposed to raw water is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. In addition, the applicant included loss of material, which is another applicable aging affect. Additionally, Table IX.C of the GALL Report states that copper-alloy (greater than 15 percent zinc) material is susceptible to a variety of aging effects and mechanisms, including loss of material and selective leaching. The staff noted that the applicant addressed loss of material in additional items for each of these components and the aging effect loss of preload, which is addressed in this AMR. However, the staff noted that the applicant did not reference the GALL Report AMR, item 3.3.1-84, for loss of material due to selective leaching in copper-alloy (greater than 15 percent zinc) bolting exposed to raw water.

By letter dated February 24, 2011, the staff issued RAI 3.3.2-37.1 requesting that the applicant justify its management of this material, environment, AERM, and AMP combination.

In its response dated March 22, 2011, the applicant stated that loss of material due to selective leaching has been added as an aging mechanism for copper alloy greater than 15 percent zinc components exposed to raw water environment. The staff finds the applicant's response acceptable because the applicant has modified the LRA to include selective leaching as an applicable aging effect for copper-alloy (greater than 15 percent zinc) bolting exposed to raw water and manage the selective leaching by the Selective Leaching of Materials Program. The staff's concern described in RAI 3.3.2.3.37-1 is resolved

The staff's evaluations of the applicant's Bolting Integrity Program and Selective Leaching of Materials Program are documented in SER Section 3.0.3.1.7 and 3.0.3.2.12, respectively. While there is no AMR for loss of preload of steel bolting exposed to raw water in the auxiliary system, the GALL Report has items for loss of preload of other material bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program and Selective Leaching of Material Program acceptable for the following reasons:

- The Bolting Integrity Program conducts bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload and inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload.
- The Selective Leaching of Materials Program conducts visual inspections and mechanical examination techniques, such as Brinell hardness testing or destructive testing, to ensure that aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

In LRA Table 3.3.2-37, the applicant stated that the copper alloy with greater than 15 percent zinc bolting exposed to air-indoor uncontrolled is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though copper alloy with greater than 15 percent zinc bolting exposed to air-indoor uncontrolled is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, Table IX.C of the GALL Report states that steel material is susceptible to a variety of aging effects and mechanisms, including loss of material. The staff noted that the applicant addressed loss of material in additional items for each of these components; therefore, the aging effect of concern is loss of preload, which is addressed in the AMR.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload of copper alloy with greater than 15 percent zinc bolting exposed to air-indoor uncontrolled in the auxiliary system, the GALL Report has items for loss of preload of bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control, such as application of appropriate gasket alignment, torque, lubricants, and preload. The program also inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

In LRA Table 3.3.2-37, the applicant stated that the copper alloy with greater than 15 percent zinc, steel, and stainless steel bolting exposed to raw water is being managed for loss of material by the Buried Piping and Tanks Inspection Program. The AMR item cites generic note G.

The staff noted that LRA Table 3.3.2-37 contains items for the same components with an aging effect of loss of preload. The staff also noted that the "parameters monitored/inspected" program element of GALL Report AMP XI.M18, "Bolting Integrity," states that, "[s]pecifically, bolting for safety-related pressure-retaining components is inspected for leakage, loss of material, cracking, and loss of preload/loss of prestress." The staff further noted that the "detection of aging effects" program element of GALL Report AMP XI.M18 states that for Classes 1, 2, and 3 bolting, system leakage tests would detect degradation of closure bolting due to crack initiation, loss of pre-stress, or loss of material because all three of these aging effects would result in joint leakage. The staff noted that in addition to loss of material, copper alloy with greater than 15 percent zinc bolting in a raw water environment would be susceptible to selective leaching. For these same LRA items, the staff issued RAI 3.3.2-37 requesting that the applicant state why it is acceptable to manage selective leaching with a visual inspection program (i.e., Bolting Integrity, Buried Piping and Tanks Inspection Program) or provide an AMR item, which credits an alternate AMP that includes mechanical examination techniques to manage the loss of material due to selective leaching aging effect for copper-alloy (greater than 15 percent Zn) bolting exposed to raw water in the service water system. The applicant's response and staff evaluation is provided in SER Section 3.3.2.3.37.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.3.1. The staff finds that the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program is acceptable for the following reasons:

- The program includes preventive actions, such as external coatings and wrappings installed to industry standard practices, and some systems are protected by a cathodic protection system.
- Periodic visual inspections will be performed starting 10 years prior to the period of extended operation and extend into both 10-year periods during the period of extended operation to ensure that coatings remain intact or uncoated bolting has not degraded.
- Plant-specific operating experience will be used to inform inspection locations.
- Alternatives to direct visual inspection such as pressure tests are capable of detecting degradation of the bolted connection.
- Selective leaching is addressed in SER Section 3.3.2.3.37.

In LRA Table 3.3.2-37, the applicant stated that for glass piping elements exposed to air-outdoor (external) or condensation (external), there is no aging effect, and no AMP is proposed. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that no aging effect is applicable for this component, material, and environment combination. For the condensation environment, GALL Report item V.F-8 states that there are no aging effects for glass exposed to raw water, and raw water is no more severe an environment than condensation. For the air-outdoor environment, glass will not exhibit aging effects that will cause its CLB function to not be met as evidenced by the widespread successful use of glass in commercial and industrial outdoor settings.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.38 Service Water Pump House Air Handling System—Aging Management Evaluation—LRA Table 3.3.2-38

The staff reviewed LRA Table 3.3.2-38, which summarizes the results of AMR evaluations for the service water pump house air handling system component groups.

The staff's review did not find any items indicating plant-specific Notes F–J, whereby the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report.

The staff's evaluation of the items with Notes A–E is documented in SER Section 3.3.2.1.

3.3.2.3.39 Spent Fuel Pool Cooling System—Aging Management Evaluation—LRA Table 3.3.2-39

The staff reviewed LRA Table 3.3.2-39, which summarizes the results of AMR evaluations for the spent fuel cooling system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for glass piping elements exposed to air-with borated water leakage (external), with no AERM and no recommended AMP citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for elastomer flexible connectors and flexible hose exposed to air with borated water leakage (external), which are being managed for hardening and loss of strength by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for stainless steel heat exchanger components exposed to treated borated water, being managed for reduction of heat transfer due to fouling by the Water Chemistry Program citing generic note H, is documented in SER Section 3.2.2.3.2.

In LRA Table 3.3.2-39, the applicant stated that the stainless steel bolting exposed to treated borated water is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though stainless steel bolting exposed to treated borated water is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, GALL Report, Revision 2, item VII.I.AP-265, states that stainless steel bolting exposed to treated borated water is only susceptible to loss of preload. The staff noted that the applicant addressed loss of material in additional items for each of these components; therefore, the aging effect of concern is loss of preload, which is addressed in the AMR.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload of stainless steel bolting exposed to treated borated water in the auxiliary system, the GALL Report has items for loss of preload of other material bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control, such as application of appropriate gasket alignment, torque, lubricants, and preload. The program also inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.40 Switchyard—Aging Management Evaluation—LRA Table 3.3.2-40

The staff reviewed LRA Table 3.3.2-40, which summarizes the results of AMR evaluations for the switchyard component groups.

The staff's evaluation for nickel-alloy components exposed borated water leakage that is not subject to an aging effect requiring management, with generic note G, is documented in SER Section 3.3.2.3.3.

The staff's evaluation for stainless steel bolting exposed to air-outdoor, being managed for loss of material by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.17.

The staff's evaluation for stainless steel bolting exposed to air-outdoor, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.17.

The staff's evaluation for stainless steel piping and fittings, valve body, expansion joint, filter housing, and tanks exposed to air-outdoor (external), which are being managed for loss of material by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.9.

The staff's evaluation for copper alloy and copper alloy with greater than 15 percent zinc valve body, instrumentation element, nozzle, filter housing, and piping and fittings, and nickel-alloy piping and fittings, valve body, expansion joint, and rupture disc exposed to air-outdoor (external), which are being managed for loss of material by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.15.

The staff's evaluation for steel bolting exposed to air-outdoor, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.1.

The staff's evaluation for aluminum flame arrestor and piping and fittings exposed to air-outdoor (external), which are being managed for loss of material by the External Surfaces Monitoring Program citing generic note G, is documented in SER Section 3.3.2.3.1.

In LRA Table 3.3.2-40, the applicant stated that the aluminum bolting exposed to air-outdoor is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though aluminum bolting exposed to air-outdoor is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. The staff noted that the applicant addressed loss of material in additional items for each of these components; therefore, the aging effect of concern is loss of preload, which is addressed in the AMR.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload of aluminum bolting exposed to air-outdoor in the auxiliary system, the GALL Report has items for loss of preload of other material bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control, such as application of appropriate gasket alignment, torque, lubricants, and preload. The program also inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

In LRA Table 3.3.2-40, the applicant stated that the aluminum bolting exposed to air-outdoor is being managed for loss of material by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though aluminum bolting exposed to air-outdoor is not specifically addressed in the GALL Report, aluminum has been shown to undergo loss of material due to general, pitting, and crevice corrosion in air (*ASM Handbook, Corrosion of Aluminum and Aluminum Alloys, Corrosion: Materials, Volume 13B*). The staff noted that the applicant addressed loss of preload in additional items for each of these components; therefore, the aging effect of concern is loss of material, which is addressed in the AMR

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of material of aluminum bolting exposed to condensation in the auxiliary system, the GALL Report has items for loss of material of other material bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program inspects the bolting through periodic visual inspections to verify that the aging effect, loss of material, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.41 Valve Stem Leak-off System—Aging Management Evaluation—LRA Table 3.3.2-41

The staff reviewed LRA Table 3.3.2-41, which summarizes the results of AMR evaluations for the valve stem leak-off system component groups.

The staff's review did not find any items indicating plant-specific Notes F–J, whereby the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report.

The staff's evaluation of the items with notes A–E is documented in SER Section 3.3.2.1.

3.3.2.3.42 Vent Gas System—Aging Management Evaluation—LRA Table 3.3.2-42

The staff reviewed LRA Table 3.3.2-42, which summarizes the results of AMR evaluations for the vent gas system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.43 Waste Gas System—Aging Management Evaluation—LRA Table 3.3.2-43

The staff reviewed LRA Table 3.3.2-43, which summarizes the results of AMR evaluations for the waste gas system component groups.

The staff's review did not find any items indicating plant-specific Notes F–J, whereby the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report.

The staff's evaluation of the items with notes A–E is documented in SER Section 3.3.2.1.

3.3.2.3.44 Waste Processing Liquid System—Aging Management Evaluation—LRA Table 3.3.2-44

The staff reviewed LRA Table 3.3.2-44, which summarizes the results of AMR evaluations for the waste processing liquid system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for steel bolting exposed to condensation, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.19.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.2.3.45 Waste Processing Liquid Drains System—Aging Management Evaluation—LRA Table 3.3.2-45

The staff reviewed LRA Table 3.3.2-45, which summarizes the results of AMR evaluations for the waste processing liquid drains system component groups.

The staff's evaluation for stainless steel bolting exposed to air-indoor, being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.3.2.3.2.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.3.3 Conclusion

The staff concludes that the applicant provided sufficient information to demonstrate that the effects of aging for the auxiliary systems 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).

3.4 Aging Management of Steam and Power Conversion Systems

This section of the SER documents the staff's review of the applicant's AMR results for the steam and power conversion systems components and component groups of the following systems:

- auxiliary steam system
- auxiliary steam condensate system

- auxiliary steam heating system
- circulating water system
- condensate system
- feedwater system
- main steam system
- steam generator blowdown system

3.4.1 Summary of Technical Information in the Application

LRA Section 3.4 provides AMR results for the steam and power conversion systems components and component groups. LRA Table 3.4.1, "Summary of Aging Management Evaluations for Steam and Power Conversion Systems," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the steam and power conversion 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.

3.4.2 Staff Evaluation

The staff reviewed LRA Section 3.4 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the steam and power conversion systems components and component groups, which are 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 ensure the applicant's claim that certain AMRs are 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 is applicable and that the applicant 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 audit evaluation are documented in SER Section 3.4.2.1.

The staff also reviewed AMRs identified by the applicant as consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the SRP-LR Section 3.4.2.2 acceptance criteria. The staff's audit evaluations are documented in SER Section 3.4.2.2.

The staff reviewed the remaining AMRs identified by the applicant as not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed are appropriate for the material-environment combinations specified. The staff's evaluations are documented in SER Section 3.4.2.3.

For SCs, which the applicant claimed are not applicable or required no aging management, the staff reviewed the AMR 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 systems 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	Consistent with GALL Report (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	Water Chemistry and One-Time Inspection	Consistent with GALL Report (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	Not applicable	Not applicable to Seabrook (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 3.4.2.2.2 and 3.4.2.2.7)
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	Lubricating Oil Analysis and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.2)

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
Steel piping, piping components, and piping elements exposed to raw water (3.4.1-8)	Loss of material due to general, pitting, crevice, and MIC, and fouling	Plant-specific	Yes	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (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	Lubricating Oil Analysis and One-Time Inspection	Consistent with GALL Report (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 MIC	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	No Yes	Buried Piping and Tanks 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 MIC	Lubricating Oil Analysis and One-Time Inspection	Yes	Not applicable	Not applicable to Seabrook (see SER Section 3.4.2.2.5)
Stainless steel piping, piping components, piping elements exposed to steam (3.4.1-13)	Cracking due to SCC	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.4.2.2.6)
Stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water > 140 °F (> 60 °C) (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)

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 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	Buried Piping and Tanks Inspection	Consistent with GALL Report (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	Lubricating Oil Analysis and One-Time Inspection	Consistent with GALL Report (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 MIC	Lubricating Oil Analysis and One-Time Inspection	Yes	Lubricating Oil Analysis and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.8)
Steel tanks exposed to air-outdoor (external) (3.4.1-20)	Loss of material, general, pitting, and crevice corrosion	Aboveground Steel Tanks	No	Not applicable	Not applicable to Seabrook (see SER Section 3.4.2.1.1)
High-strength steel closure bolting exposed to air with steam or water leakage (3.4.1-21)	Cracking due to cyclic loading, SCC	Bolting Integrity	No	Not applicable	Not applicable to Seabrook (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
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 and loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity and Buried Piping and Tanks Inspection	Consistent with GALL Report (see SER 3.4.2.1.2)
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water > 140 °F (> 60 °C) (3.4.1-23)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to Seabrook (see SER Section 3.4.2.1.1)
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	Closed-Cycle Cooling Water System	Consistent with GALL Report
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	Closed-Cycle Cooling Water System	Consistent with GALL Report
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 Seabrook (see SER Section 3.4.2.1.1)
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 Seabrook (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
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 and Buried Piping and Tanks Inspection	Consistent with GALL Report (see SER Section 3.4.2.1.3)
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
Steel heat exchanger components exposed to raw water (3.4.1-31)	Loss of material due to general, pitting, crevice, galvanic, and MIC, and fouling	Open-Cycle Cooling Water System	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.4.2.1.4)
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 MIC	Open-Cycle Cooling Water System	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.4.2.1.5)
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	Not applicable	Not applicable to Seabrook (see SER Section 3.4.2.1.1)
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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.4.2.1.6)

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
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	Selective Leaching of Materials	Consistent with GALL Report
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	Selective Leaching of Materials	Consistent with GALL Report
Steel, stainless steel, and nickel-based 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 and Steam Generator Tube Integrity	Consistent with GALL Report (see SER Section 3.4.2.1.7)
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	Boric Acid Corrosion	Consistent with GALL Report
Stainless steel piping, piping components, and piping elements exposed to steam (3.4.1-39)	Cracking due to SCC	Water Chemistry	No	Water Chemistry, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.1.8)
Glass piping elements exposed to air, lubricating oil, raw water, and treated water (3.4.1-40)	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) (3.4.1-41)	None	None	No	None	Consistent with GALL Report
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 Seabrook (see SER Section 3.4.2.1.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (3.4.1-43)	None	None	No	None	Consistent with GALL Report
Steel, stainless steel, aluminum, and copper-alloy piping, piping components, and piping elements exposed to gas (3.4.1-44)	None	None	No	None	Consistent with GALL Report

The staff's review of the steam and power conversion systems components and component groups followed one of several approaches. One approach, documented in SER Section 3.4.2.1, 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 3.4.2.2, 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 3.4.2.3, 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 steam and power conversion systems components is documented in SER Section 3.0.3.

3.4.2.1 Aging Management Review Results 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 systems components:

- Bolting Integrity Program
- Boric Acid Corrosion Program

- Buried Piping and Tanks Inspection Program
- Closed-Cycle Cooling Water System Program
- External Surfaces Monitoring Program
- Flow-Accelerated Corrosion Program
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program
- Lubricating Oil Analysis Program
- One-Time Inspection Program
- Open-Cycle Cooling Water System Program
- Selective Leaching of Materials Program
- Water Chemistry Program

LRA Tables 3.4.2-1 through 3.4.2-8 summarize AMRs for the steam and power conversion systems components and component groups and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine if 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 item describing how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with Notes A–E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR 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 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 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 items to verify consistency with the GALL Report and to ensure 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 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 items to verify consistency with the GALL Report. The staff also determined whether the AMR 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 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 items to verify consistency with the GALL Report. The staff confirmed whether the AMR item of the different component was applicable to the component under review and whether the exceptions to the GALL Report AMPs was 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 item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff reviewed these 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 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.

3.4.2.1.1 Aging Management Review Results Identified as Not Applicable

In LRA Table 3.4.1, for items 3.4.1-20, 3.4.1-21, 3.4.1-23, 3.4.1-26, 3.4.1-27, and 3.4.1-33, the applicant claimed that they were not applicable. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results that are applicable for these items.

LRA Table 3.4.1, item 3.4.1-42 addresses steel piping, piping components, and piping elements exposed to controlled indoor air (external) and states that there are no aging effects, aging mechanisms, or AMPs. The GALL Report, Table VIII, item VIII.I-13 (SP-1) identifies no aging effect or aging mechanism and AMP is recommended for this component group exposed to this environment. Therefore, the staff finds the applicant's determination acceptable.

3.4.2.1.2 Loss of Material due to General, Pitting, and Crevice Corrosion

LRA Table 3.4.1, item 3.4.1-22, addresses steel bolting and closure bolting exposed to air-indoor, which are being managed for loss of material. In Supplement 2 to the LRA, dated November 15, 2010, the applicant stated that it will use the Buried Piping and Tanks Inspection Program to manage the effects of aging on bolting exposed to air-indoor uncontrolled (external) in the auxiliary steam condensate and auxiliary steam heating systems. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity," to ensure that these aging effects are adequately managed. For the bolting AMR results in these two systems, the applicant cited generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M18 recommends Classes 1, 2, and 3 components using ASME Code Section XI, Tables IWB 2500-1, IWC 2500-1, or IWD 2500-1, which mainly require either visual inspection or volumetric examination or both to manage the aging of these components. For other pressure-retaining bolting, AMP XI.M18 recommends periodic system walkdowns to detect leakage before the leakage becomes excessive. In its review of components associated with LRA Table 3.4.1, item 3.4.1-22, for which the applicant cited generic note E, the staff noted that the Buried Piping and Tanks Inspection Program proposes to manage the aging of steel bolting through the use of the following:

- preventive actions, such as external coatings and wrappings installed in accordance with industry standard practices, and some systems protected by a cathodic protection system
- periodic visual inspections, which will be performed starting 10 years prior to the period of extended operation and extend into both 10-year periods during the period of extended operation to ensure that coatings remain intact or uncoated bolting has not degraded
- alternatives to direct visual inspection such as pressure tests, which are capable of detecting degradation of the bolted connection

The staff's evaluation of the applicant's Inspection of Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.3.1. In its review of components associated with LRA Table 3.4.1, item 3.4.1-22, the staff finds that the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program acceptable for the following reasons:

- The program includes preventive actions, such as external coatings and wrappings, installed in accordance with industry standard practices.
- Periodic visual inspections will be performed starting 10 years prior to the period of extended operation and extend into both 10-year periods during the period of extended operation to ensure that coatings remain intact or uncoated bolting has not degraded.
- Plant-specific operating experience will be used to inform inspection locations.
- Alternatives to direct visual inspection, such as pressure tests, are capable of detecting degradation of the bolted connection.

The staff concludes that the applicant 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 Corrosion

LRA Table 3.4.1, item 3.4.1-28, addresses steel external surfaces exposed to air-indoor uncontrolled (external), which are being managed for loss of material due to general corrosion. In Supplement 2 to the LRA, the applicant credits the Buried Piping and Tanks Inspection Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The applicant stated that the components are in an underground pit with an external environment of air-indoor uncontrolled, and the plant-specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect.

GALL Report AMP XI.M36 recommends using visual inspections for general corrosion to manage the aging effect of the item. In its review of components associated with LRA Table 3.4.1, item 3.4.1-28, for which the applicant cited generic note E, the staff noted that the Buried Piping and Tank Inspection Program proposes to manage the aging of piping and components through the use of periodic visual inspections. The staff also noted that although the components are exposed to an external air-indoor uncontrolled environment, they are in an underground pit.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.3.1. In its review of components associated with item 3.4.1-28, the staff finds the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program acceptable because it includes visual inspections that can detect loss of material on the external surfaces of the components, and the components are in an underground pit.

The staff concludes that the applicant 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).

3.4.2.1.4 Loss of Material Due To General, Pitting, Crevice, Galvanic, and Microbiologically-Influenced Corrosion and Fouling

LRA Table 3.4.1, item 3.4.1-31, addresses steel heat exchanger components exposed to raw water, which are being managed for loss of material due to general, pitting, crevice, galvanic, and MIC and fouling. The applicant credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, the GALL Report AMP XI.M20 Program recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.4.1, item 3.4.1-31, 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 the aging of steel heat exchanger components through the use of periodic inspection on the internal surfaces of components. It was not clear to the staff how the opportunistic visual inspections will be able to manage aging of components in a raw water system that does not include chemical treatments or surveillances. By letter dated January 5, 2011, the staff issued RAI 3.3.2.2-1 requesting that the applicant justify the use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component Program, which is only a visual inspection program, to manage aging in the raw water environment.

In its response dated February 3, 2011, the applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was chosen because the internal raw water environments are not covered by any other AMP. The applicant also stated that its conclusion to use this AMP is supported by information in Revision 2 to the GALL Report, that this program applies to components exposed to any water systems not included in the open-cycle cooling water, closed treated water, or fire water AMPs. The applicant further stated that its equipment inspections have been successful at identifying and resolving corrosion or degradation before it affects the ability of the component to perform its intended function. The staff finds the applicant's response acceptable because the GALL Report, Revision 2, allows for managing of components exposed to raw water, which are not part of the open-cycle cooling water system, to be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component Program. Therefore, the applicant's proposal complies with the current staff position. The staff's concern described in RAI 3.3.2.2-1 is resolved.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. In its review of components associated with LRA Table 3.4.1, item 3.4.1-31, 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 the program conducts visual inspections during periodic system surveillances or maintenance activities when internal surfaces are accessible and monitors parameters such as corrosion, corrosion byproducts, coating degradation, scale/deposits, pits, and surface discoloration and discontinuities. In addition, the staff finds that the use of Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable to manage these components exposed to raw water because the raw water is associated with potable water and is not part of the open-cycle cooling system; therefore, the use of this program is consistent with the current staff position.

The staff concludes that the applicant 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).

3.4.2.1.5 Loss of Material Due To Pitting, Crevice, and Microbiologically-Influenced Corrosion

LRA Table 3.4.1, item 3.4.1-32, addresses stainless steel and 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 MIC. The applicant credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, the GALL Report AMP XI.M20 program recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.3.1, item 3.4.1-32, 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 the aging of stainless steel and copper-alloy piping, piping components, and piping elements through the use of periodic inspection on the internal surfaces of components. It was not clear to the staff how the opportunistic visual inspections will be able to manage aging of components in a raw water system that does not include chemical treatments or surveillances. By letter dated January 5, 2011, the staff issued RAI 3.3.2.2-1 requesting that the applicant justify the use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component Program, which is only a visual inspection program, to manage aging in the raw water environment.

In its response dated February 3, 2011, the applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was chosen because the internal raw water environments are not covered by any other AMP. The applicant also stated that its conclusion to use this AMP is supported by information in Revision 2 to the GALL Report, that this program applies to components exposed to any water systems not included in the open-cycle cooling water, closed treated water, or fire water AMPS. The applicant further stated that its equipment inspections have been successful at identifying and resolving corrosion or degradation before it affects the ability of the component to perform its intended function. The staff finds the applicant's response acceptable because the GALL Report, Revision 2, allows components exposed to raw water, which are not part of the open-cycle cooling water system, to be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component Program; therefore, the applicant's proposal complies with the current staff position. The staff's concern described in RAI 3.3.2.2-1 is resolved.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. In its review of components associated with LRA Table 3.4.1, item 3.4.1-32, 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 the program conducts visual inspections during periodic system surveillances or maintenance activities when internal surfaces are accessible and monitors parameters such as corrosion, corrosion byproducts, coating degradation, scale/deposits, pits, and surface discoloration and discontinuities. In addition, the staff finds that the use of Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable to manage these components exposed to raw water because the raw water is associated with potable water or radioactive liquid waste drainage systems and not part of the open-cycle cooling system. Therefore, the use of this program is consistent with the current staff position.

The staff concludes that the applicant 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).

3.4.2.1.6 Reduction of Heat Transfer Due To Fouling

LRA Table 3.4.1, item 3.4.1-34, addresses steel, stainless steel, and copper-alloy heat exchanger tubes exposed to raw water, which are being managed for reduction of heat transfer due to fouling. The applicant credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E indicating that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited.

GALL Report AMP XI.M20 recommends using condition and performance monitoring programs to manage the aging of these items. In addition, the GALL Report AMP XI.M20 program recommends using chemical treatments whenever the potential for biological fouling species exists and also recommends the use of periodic flushing. In its review of components associated with LRA Table 3.4.1, item 3.4.1-34, 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 the aging of steel, stainless steel, and copper-alloy heat exchanger tubes through the use of periodic inspection on the internal surfaces of components. It was not clear to the staff how the opportunistic visual inspections will be able to manage aging of components in a raw water system that does not include chemical treatments or surveillances. By letter dated January 5, 2011, the staff issued RAI 3.3.2.2-1 requesting that the applicant justify the use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, which is only a visual inspection program, to manage aging in the raw water environment.

In its response dated February 3, 2011, the applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was chosen because the internal raw water environments are not covered by any other AMP. The applicant also stated that its conclusion to use this AMP is supported by information in Revision 2 of the GALL Report, that this program applies to components exposed to any water systems not included in the open-cycle cooling water, closed treated water, or fire water AMPs. The applicant further stated that its equipment inspections have been successful at identifying and resolving corrosion or degradation before it affects the ability of the component to perform its intended function. The staff finds the applicant’s response acceptable because the GALL Report, Revision 2, allows components exposed to raw water, that not part of the open-cycle cooling water system, to be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component Program. Therefore, the applicant’s proposal complies with the current staff position. The staff’s concern described in RAI 3.3.2.2-1 is resolved.

The staff’s evaluation of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. In its review of components associated with LRA Table 3.4.1, item 3.4.1-34, 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 the program conducts visual inspections during periodic system surveillances or maintenance activities when internal surfaces are accessible and monitors parameters such as corrosion, and corrosion byproducts. In addition, the staff finds that the use of Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable to manage these components exposed to raw water because the raw water is associated with potable water and not part of the open-cycle cooling system. Therefore, the use of this program is consistent with the current staff position.

The staff concludes that the applicant 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).

3.4.2.1.7 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.4.1, item 3.4.1-37, addresses nickel-alloy steam generator orifices, steam generator feedwater inlet rings (J tube), steam generator feedwater nozzles, and steam generator tubes exposed to secondary feedwater and steam, which are being managed for loss of material due to pitting and crevice corrosion. The LRA credits the Water Chemistry Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M2, “Water Chemistry” to ensure that these aging effects are adequately managed. The associated AMR items cite generic note A.

In its review of components associated with item 3.4.1-37, the staff noted three potential inconsistencies between the aging management approach proposed by the applicant for these components and the approach contained in, or implied by, the GALL Report.

The first potential inconsistency involves the environment to which the components are exposed. For LRA Table 2 items contained in Table 3.1.2-4, which are subordinate to LRA Table 3.4.1-37, the environment listed is “secondary feedwater/steam.” The environment for the corresponding item in the GALL Report is steam. The GALL Report recommends managing loss of material for nickel-alloy components exposed to steam through the use of the GALL Report AMP XI.M2, Water Chemistry. Alternatively, the GALL Report recommends managing cracking due to SCC for nickel-alloy components exposed to steam and water environments through the use of GALL Report AMP XI.M2, “Water Chemistry,” and an inspection-based verification program. For piping and pressure boundary components, the Inspection Program is typically GALL Report AMP XI.M32, “One Time Inspection,” or GALL Report AMP XI.M1, “ASME Section XI, Inservice Inspection.” For steam generator internal components, the Inspection Program is typically GALL Report AMP XI.M19, “Steam Generator Tube Integrity.” This difference in environments appears to make the use of item 3.4.1-37 inappropriate for these components.

The second potential inconsistency involves the aging effects proposed for these components. Based on LRA Table 3.2.1-4, “Steam Generator,” it appears that the aging effects “cracking” and “loss of material” are proposed for nickel-alloy steam generator tubes, while only “loss of material” is proposed for the remaining nickel-alloy components. Although the remaining components are not specifically addressed in the GALL Report, the staff finds no specific distinction that would permit the applicant to propose only “loss of material” for any of the components under consideration.

The third potential inconsistency involves the classification of the components. SRP-LR Table 3.4-1, ID 37, classifies the components under consideration as “piping, piping components, or piping elements.” The staff agrees with the applicant that the orifices and the steam generator feedwater nozzle (thermal sleeve) may be appropriately considered piping, piping components, and piping elements. The staff finds that the steam generator feedwater inlet ring (J tube) and the steam generator tubes are more appropriately classified as steam generator internal components. This classification appears to make the use of item 3.4.1-37 inappropriate for the J tubes and the steam generator tubes.

To address these potential inconsistencies in aging management approach, the staff issued RAI 3.4.1-37-1 by letter dated January 5, 2011, requesting that the applicant do the following:

(a) propose to manage aging of these components using water chemistry and an appropriate verification AMP, as indicated by the GALL Report, for the management of aging in a secondary feedwater or steam environment or justify why the use of a verification AMP is either inconsistent with the GALL Report or technically unnecessary

(b) justify why is it unnecessary to consider both the aging effects “loss of material” and “cracking” for each of the components under consideration

(c) classify the steam generator feedwater inlet ring (J tube) and the steam generator tubes as steam generator internal components (making the appropriate verification AMP the Steam Generator Tube Integrity Program) or justify why these components should be considered piping, piping components, or piping elements, as proposed by item 3.4.1-37

In its response dated February 3, 2011, the applicant took the following actions:

(a) redesignated the steam generator feedwater inlet ring (J tube) and steam generator tubes as steam generator components, as opposed to piping, and proposed to manage the aging associated with these components through the use of its Water Chemistry and Steam Generator Tube Integrity Programs

(b) added the aging effect “cracking” for components as necessary to ensure that both the aging effects “loss of material” and “cracking” were managed for each component under consideration

(c) acknowledged that the “steam” environment described in SRP-LR Table 3.4.1, ID 37, is inconsistent with the secondary feedwater or steam environment to which these components are exposed

As a result of this acknowledgement, the applicant changed the designation of these items from SRP-LR Table 3.4.1, ID 37, generic note A, to “not consistent with the GALL Report,” generic note H.

The staff reviewed each of these actions with respect to its consistency with the GALL Report, its sufficiency to manage aging and its responsiveness to the RAI. The staff determined the following:

(a) The applicant’s redesignation of the inlet feedwater ring and steam generator tubes—from being consistent with SRP-LR Table 3.1.4, ID 37, to being not consistent with the GALL Report—is acceptable because it appropriately identifies these components as being internal to the steam generator. The applicant’s use of its Water Chemistry and Steam Generator Tube Integrity AMPs to manage aging is acceptable because these programs are generally recommended by the GALL Report for managing the aging of steam generator internal components and will adequately manage the aging of these components.

(b) The applicant’s redesignation of the feedwater nozzle thermal sleeve and orifice—from being consistent with SRP-LR Table 3.1.4, ID 37, to being not consistent with the GALL Report—may not be acceptable. It appears to the staff that the components, materials, and aging effects currently under consideration are consistent with SRP-LR Table 3.1-1, ID 84. The applicant’s use of its Water Chemistry AMP to manage this aging also may be not acceptable as SRP-LR Table 3.1-1, ID 84, recommends that aging be managed through the use of GALL Report AMPS XI.M2, “Water Chemistry,” and either AMP XI.M32, “One Time Inspection,” or AMP XI.M1, “ASME Section XI, Inservice Inspection.” The staff notes that, in its response to RAI 3.4.1-37-1, the applicant stated that these components were not available for inspection. The staff also notes that these components have been addressed in many recent license renewal SERs. While there have been differences in the approaches to the management of aging of these components from plant to plant, in each case, the SER indicates that the accepted method of aging management involves the use of an AMP to manage water chemistry and an AMP to perform at least a one-time inspection to verify the efficacy of the Water Chemistry Program. This indicates to the staff that Water Chemistry and Inspection Programs are necessary for adequate aging management and that these components are generally inspectable.

(c) The applicant’s addition of the aging effect “cracking” for components as necessary to ensure that both the aging effects “loss of material” and “cracking” were managed for each component under consideration is acceptable because the applicant has now identified all the reasonable aging effects for these components and because the programs proposed to manage this aging are adequate.

(d) In combination, the applicant's actions (a) and (b) are fully responsive (although not fully acceptable) to RAI issues (a) and (c). The applicant's action (b) is fully responsive (and fully acceptable) to RAI issue (b).

To resolve the issue addressed in Subparagraph (b) above, the staff issued RAI 3.4.1-37-2 by letter dated March 7, 2011, requesting that the applicant do the following:

- demonstrate why the aging management guidance provided by SRP-LR Table 3.4-1, ID 84, need not be followed
- demonstrate why the components under consideration are inspectable at other plants and not at the applicant's plant
- propose to manage aging of these components in a manner consistent with or equivalent to SRP-LR Table 3.4-1, ID 84

In its response dated April 5, 2011, the applicant did the following:

- stated that it has recirculating steam generators and, therefore, chose not to use SRP-LR Table 3.1-1, ID 84, for the components under consideration because this item refers only to item R-36, which appears only in GALL Report Table IV.D2, which addresses only once through steam generators
- described the construction and location of the steam generator steam flow restricting orifice and concluded that, due to the location of the component and the lack of manways or other access points in the vicinity of the component, inspection of the component by either direct or remote means was not practical without a plant modification
- described the construction and location of the steam generator feedwater nozzle thermal sleeve and concluded direct visual inspection of this component was not possible but remote visual inspection was possible via the feedwater ring J tube opening
- proposed that, due to the lack of industry experience of aging effects associated with the steam generator steam flow restricting orifice and the absence of a recommendation to inspect these components in the EPRI Steam Generator Integrity Assessment Guidelines (EPRI 1012987, Revision 2), the use of the Water Chemistry Program AMP was sufficient to manage aging of this component without the use of the One-Time Inspection AMP
- proposed to include the steam generator feedwater nozzle thermal sleeve in its Steam Generator Tube Integrity Program to verify the effectiveness of its Water Chemistry Program despite the lack of specific plant and industry operating experience showing a need to inspect this component or an EPRI recommendation to inspect the component

The staff reviewed each of these actions with respect to its consistency with the GALL Report, its sufficiency to manage aging, and its responsiveness to the RAI. The agrees with the applicant's observation that SRP-LR Table 3.1-1, ID 84, applies specifically only to once through steam generators (Table IV.D2). The staff, therefore, accepts the applicant's use of generic note H as opposed to using Table 3.1-1, ID 84, generic note A. Given that components meeting the general criteria of Table 3.1-1, ID 84, are present in both once through and recirculating steam generators, the staff will consider inclusion of this AMR item in both Tables IV.D2 and D1 in a future revision of the GALL Report. The staff finds no fault with the applicant's description of the steam generator steam flow restricting orifice. The staff agrees that, absent manways or other means of access in the vicinity of this component, inspection is not reasonably possible at this plant. The staff finds no fault with the applicant's description of the steam generator feedwater nozzle thermal sleeve. The staff agrees that direct inspection of this component is not possible but that remote inspection should be possible. Given the lack of specific plant or industry operating experience, which points directly to the need to inspect the steam generator steam flow restricting orifice and the significance of the modifications to the plant which would be necessary to inspect this component, the staff agrees with the applicant's proposal to manage the aging of this component solely through the use of its Water Chemistry Program. Lastly, the staff agrees with the applicant's proposal to manage the aging of its steam generator feedwater nozzle thermal sleeve through the use of its Water Chemistry and Steam Generator Tube Integrity Programs. The Steam Generator Tube Integrity Program contains provisions for inspections, which will permit the verification of the effectiveness of the Water Chemistry Program in preventing component degradation.

The staff finds that the applicant has been fully responsive to the questions raised in the RAIs and that the applicant's proposals included in their RAI responses are technically sufficient to accomplish their intended goals. The staff's concerns described in RAIs 3.4.1-37-1 and 3.4.1-37-2 are resolved.

The staff's evaluation of the applicant's Water Chemistry Program and Steam Generator Tube Integrity Program are documented in SER Sections 3.0.3.1.2 and 3.0.3.2.2, respectively. In its review of components associated with LRA Table 3.4.1, item 3.4.1-37, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program and Steam Generator Tube Integrity Program acceptable because the Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate the environmental effect on the aging and establishes corrective actions if the parameters exceed the limits so that the environmental effect on the aging is minimized. Also, the Steam Generator Tube Integrity Program contains provisions for inspections, which will permit the verification of the effectiveness of the Water Chemistry Program in preventing component degradation. Therefore, the use of these programs are consistent with the current staff position.

The staff concludes that the applicant 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).

3.4.2.1.8 Cracking due to Stress Corrosion Cracking

In LRA Table 3.4.1, item 3.4.1-39, addresses stainless steel piping, piping components, and piping elements exposed to steam, which are being managed for cracking due to SCC. The LRA credits the Water Chemistry Program and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed. The associated AMR items cite generic Notes A, C, and E.

GALL Report AMP XI.M2 recommends using water chemistry control to mitigate the aging of these items. In its review of components associated with item 3.4.1-39, for which the applicant cited generic note E, the staff noted that LRA Table 3.4.2-3 indicates that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is proposed to manage cracking due SCC of stainless steel heat exchanger components, valve body, and filter elements. The staff also noted that LRA Section B.2.1.25 describes that the applicant's program uses inspections of opportunity and that the inspection techniques used to detect this aging effect of the components will be either visual inspection with a magnified resolution, as described in 10 CFR 50.55a(b)(2)(xxi)(A), or an ultrasonic inspection method. By letter dated January 5, 2011, the staff issued RAI 3.4.2.3-01 requesting that the applicant clarify why the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, which relies on inspections of opportunity without water chemistry control, is adequate to detect and manage cracking due to SCC in the stainless steel components exposed to steam.

In its response dated February 3, 2011, the applicant stated that the makeup water for the auxiliary steam heating system in LRA Table 3.4.2-3 is potable water obtained from the Town of Seabrook, which is not the same steam environment listed in items 3.4.1-37 and 3.4.1-39. The applicant also stated that the PWR secondary Plant Water Chemistry Program is not applicable to potable water; therefore, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a more appropriate program for managing the aging of these components. The applicant further stated that the applicant will provide for a one-time inspection of the stainless steel components addressed in Table 3.4.2-3, and any evidence of cracking will be documented and evaluated under the Corrective Action Program. In addition, the applicant stated that the LRA has been revised to credit the One-Time Inspection Program that will verify that cracking does not occur. The applicant also revised the generic note for these components from E to G indicating that, for this component and material, the environment is not in the GALL Report.

Based on its review, the staff finds the applicant's response to RAI 3.4.2.3-01 acceptable because the applicant clarified that the source of the makeup water is potable water, to which the Water Chemistry Program is not applicable. The staff also finds that LRA Tables 3.4.2-3 and 3.4.1 and LRA Section B.2.1.20 have been revised to implement the One-Time Inspection Program, which will confirm that cracking does not occur. The staff also finds that the One-Time Inspection Program is adequate to confirm the effectiveness of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for managing cracking due to SCC of the components. The staff's concern described in RAI 3.4.2.3-01 is resolved.

The staff reviewed the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and One-Time Inspection Program, and the staff's evaluations are documented in SER Sections 3.0.3.2.15 and 3.0.3.1.8, respectively. In its review, the staff finds the applicant's use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and One-Time Inspection Program acceptable to manage the aging effect for the following reasons:

- The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program includes periodic inspections to detect cracking using either visual inspection with a magnified resolution, as described in 10 CFR 50.55a (b)(2)(xxi)(A), or an ultrasonic inspection method, which is adequate to detect the aging effect.
- The source of water, which is converted to steam, is potable water, to which the Water Chemistry Program is not applicable.
- The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, with periodic inspections, is also augmented by the One-Time Inspection Program to confirm that cracking does not occur.

- Any evidence of cracking will be documented and evaluated under the Corrective Action Program, which is adequate to manage the aging effect.

In its review of components associated with item 3.4.1-39, for which the applicant cited generic note C, the staff noted that the GALL Report does not contain a specific AMR item for cracking due to stress corrosion of stainless steel heat exchanger components exposed to steam. The staff also noted that for heat exchanger components of other materials and environments, the GALL Report typically recommends a Water Chemistry Program in conjunction with an Inspection Program that verifies the effectiveness of the Water Chemistry Program to manage cracking due to SCC.

In LRA Tables 3.3.2-15 and 3.4.2-5, the applicant indicated that cracking due to SCC is applicable for stainless steel heat exchanger components (FP-E-46 and FP-E-47 and 1-CO-E-111 components, respectively) exposed to steam and that the applicant's Water Chemistry Program is credited to manage the aging effect in these components associated with LRA item 3.4.1-39. By letter dated January 5, 2011, the staff issued RAI 3.3.2.15-01 asking the applicant to justify why the Water Chemistry Program alone is adequate to manage cracking due to SCC in these heat exchanger components exposed to steam.

In its response dated February 3, 2011, the applicant stated that the external steam environment of the heat exchanger tubes in CO-E-111 is steam supplied from the main steam system, which is subject to the Water Chemistry Program; therefore, the selection of Water Chemistry Program as the AMP is appropriate. The applicant also stated that, in addition to the Water Chemistry Program, the heat exchanger tubes for CO-E-111 will be inspected under the One-Time Inspection Program to verify that the cracking does not occur and that any evidence of cracking will be documented and evaluated under the Corrective Action Program. The staff finds that this portion of the applicant's response regarding the aging management of the heat exchanger components (1-CO-E-111 tubes) acceptable because the applicant revised the LRA to implement the One-Time Inspection Program that will confirm that cracking due to SCC does not occur and that the Water Chemistry Program is effective to manage the aging effect.

In its response, the applicant also stated that the steam environment listed in Table 3.3.2-15 for the other heat exchangers (FP-E-46 and FP-E-47) is potable water converted to steam, which is not the same steam environment listed in item 3.4.1-39. The applicant further stated that the shell side steam environment for the two heat exchangers comes from the auxiliary steam heating system, which uses potable water. In addition, the applicant stated that the potable water is not subject to the Water Chemistry Program and that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a more appropriate program to manage the aging of these components. In addition, the applicant stated that it has preventive maintenance activities already in place to clean and inspect the external surface of the heat exchanger tubes at a frequency of approximately every 4 years and that, if evidence of cracking is found, it will be documented and evaluated under the Corrective Action Program. The applicant stated that, as part of the response to this RAI, the other components of these two heat exchangers (FP-E-46 and FP-E-47), which were inadvertently assigned to the Water Chemistry Program, are being reassigned to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The applicant stated that the generic note for these components (FP-E-46 and FP-E-47 components) was revised from C to G, indicating that the environment is not in the GALL Report for this component and material.

Based on its review, the staff finds the applicant's response to this portion of RAI 3.3.2.15-01 acceptable because the applicant clarified that the Water Chemistry Program is not applicable to the components (FP-E-46 and FP-E-47) exposed to potable water. Additionally, the applicant revised the LRA to credit its Inspection of Internal Surfaces in Miscellaneous Piping Program, which includes periodic inspection capable of detecting cracking due to SCC. The staff also finds the applicant's response acceptable because the applicant revised the LRA to manage the aging effect of the heat exchanger components (1-CO-E-111 tubes) exposed to steam supplied from the main steam system using the Water Chemistry Program, augmented by the One-Time Inspection Program, which will confirm the effectiveness of the Water Chemistry Program. The staff's concern described in RAI 3.3.2.15-01 is resolved.

The staff reviewed the Water Chemistry Program, One-Time Inspection Program, and Inspection of Internal Surfaces in Miscellaneous Piping Program, and the staff's evaluations are documented in SER Sections 3.0.3.1.2, 3.0.3.1.8, and 3.0.3.2.15, respectively. In its review, the staff finds the applicant's use of the Water Chemistry Program, augmented by the One-Time Inspection of Internal Surfaces in Miscellaneous Piping Program, acceptable to manage the aging effect for the following reasons:

- The Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate the environmental effect on the aging.
- The Water Chemistry Program also takes corrective actions if the parameters exceed the limits so that the environmental effect on the aging is minimized.
- The One-Time Inspection Program includes a one-time inspection of selected components to confirm the effectiveness of the Water Chemistry Program for managing cracking due to SCC in a manner consistent with the GALL Report and SRP-LR.
- The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program includes periodic inspections, which are capable to detect cracking due to SCC, and if evidence of cracking is found, it will be documented and evaluated under the Corrective Action Program.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and 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 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).

3.4.2.2 Aging Management Review Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.4.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the steam and power conversion systems components and component groups and provides 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 MIC and fouling
- reduction of heat transfer due to fouling
- loss of material due to general, pitting, crevice, and MIC

- cracking due to SCC
- loss of material due to pitting and crevice corrosion
- loss of material due to pitting, crevice, and MIC
- loss of material due to general, pitting, crevice, and galvanic corrosion
- 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 if 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 3.4.2.2. The staff's review of the applicant's further evaluation follows.

3.4.2.2.1 Cumulative Fatigue Damage

LRA Section 3.4.2.2.1, which is associated with LRA Table 3.4.1, item 3.4.1-1, addresses steel piping, piping components, and piping elements exposed to steam or treated water being managed for cumulative fatigue damage. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3, and is required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that the TLAA identified for the steam and power conversion systems is addressed separately in LRA Section 4.3.

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. 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 SRP-LR Section 4.3, "Metal Fatigue Analysis." The staff reviewed the applicant's AMR items and finds that the AMR results are consistent with the recommendations of the GALL Report and SRP-LR for managing cumulative fatigue damage in steel piping, piping components, and piping elements exposed to steam or treated water.

Based on its review, the staff concludes that the applicant met the SRP-LR Section 3.4.2.2.1 criteria. For those items that apply to LRA Section 3.4.2.2.1, the staff determined that the LRA is consistent with the GALL Report, and the applicant demonstrated that it will adequately manage the effects of aging 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). SER Section 4.3 documents the staff's review of the applicant's evaluation of the TLAA for these components.

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 following criteria in SRP-LR Section 3.4.2.2.2:

(1) LRA Section 3.4.2.2.2.1, is associated with LRA Table 3.4.1, items 3.4.1-2, 3.4.1-3, 3.4.1-4, and 3.4.1-6 (steel only). It addresses steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water, and steel piping, piping components, piping elements exposed to steam, 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 criteria in SRP-LR

Section 3.4.2.2.2, item 1, state 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 control of water chemistry to mitigate degradation, and a one-time inspection of select components at susceptible locations is an acceptable method to determine if an aging effect does not occur or progressing very slowly such that the component's intended function will be maintained during the period of extended operation. The applicant addressed the further evaluation criteria of the SRP-LR by stating that loss of material due to general, pitting, and crevice corrosion of steel piping, tanks, and heat exchanger components exposed to treated water, and steel piping, piping components, piping elements exposed to steam will be managed by the Water Chemistry and One-Time Inspection Programs.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. In its review of components associated with items 3.4.1-2, 3.4.1-3, 3.4.1-4, and 3.4.1-6, the staff finds that the applicant met the further evaluation criteria, and the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection Programs is acceptable because the Water Chemistry Program uses chemical sampling and corrective actions to ensure that impurities are minimized to reduce aging due to loss of material. Additionally, the One-Time Inspection Program will perform a one-time inspection of select components to verify the effectiveness of the Water Chemistry Program for managing the aging effects of loss of material.

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 items that apply to LRA Section 3.4.2.2.2.1, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 3.4.2.2.2.2, referenced by LRA Table 3.4.1, item 3.4.1-7, addresses steel piping, piping components, and piping elements exposed to lubricating oil, 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 criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material through examination of susceptible locations in steel piping, piping components, and piping elements exposed to lubricating oil in the feedwater and main steam systems.

The staff reviewed LRA Section 3.4.2.2.2.2 against the criteria in SRP-LR Section 3.4.2.2.2, item 2, which state 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 AMP 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. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil contaminant control should be confirmed to ensure that corrosion does not occur. The

SRP-LR also states that the GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the Lubricating Oil Analysis Program for which a one-time inspection of selected 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's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. In its review of components associated with item 3.4.1-7, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report. Additionally, the applicant stated that the One-Time Inspection Program will be used to examine stainless steel piping, piping components, and piping elements to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.4.2.2.2, item 2; therefore, the applicant's AMR is consistent with the GALL Report.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.2, item 2, criteria. For those items that apply to LRA Section 3.4.2.2.2.2, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 is associated with LRA Table 3.4.1, item 3.4.1-8, and 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, galvanic, and MIC and fouling by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The criteria in SRP-LR Section 3.4.2.2.3 states that loss of material due to general, pitting, crevice, and MIC and fouling could occur in steel piping, piping components, and piping elements exposed to raw water. The SRP-LR also states that the GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed. The SRP-LR further states that the acceptance criteria for the further evaluation of the plant-specific AMP are described in BTP RSLB-1. The applicant addressed the further evaluation criteria of the SRP-LR by stating that loss of material due to pitting, crevice, galvanic, and MIC in steel piping components and tanks exposed to raw water will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff noted that LRA Table 3.4-1, item 3.4.1-8, states that fouling was excluded as an aging mechanism since the raw water is associated with potable domestic water from the Town of Seabrook.

The applicant stated that for item 3.4.1-8, the applicability is limited to steel auxiliary steam condensate and auxiliary steam heating system piping components and tanks exposed to raw water. The staff noted that a search of LRA Section 3.4 and the applicant's UFSAR confirmed that no in-scope piping, piping components, piping elements, and tanks exposed to raw water are present in the steam and power conversion systems, except for those listed in LRA Section 3.4.2.2.3 and item 3.4.1-8.

In its review of components associated with item 3.4.1-8, the staff noted that the applicant's proposed program to manage steel and gray cast iron components in raw water is only an Opportunistic Inspection Program and does not include chemical treatments to eliminate biological activity. By letter dated January 5, 2011, the staff issued RAI 3.4.2.2-1 requesting that the applicant justify how loss of material in steel and gray cast iron components exposed to raw water will be managed in the absence of a preventive program with chemical sampling and corrective actions, in light of the potential infrequent inspections that may occur due to managing these components with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

In its response dated February 3, 2011, the applicant stated that the makeup water to the auxiliary steam condensate and auxiliary steam heating systems is potable water or drinking water, which is not considered treated water as it does not begin as demineralized water and receive any other chemical treatment; therefore, it is considered a raw water environment. The applicant also stated that the Town of Seabrook's drinking water is not covered by the Open-Cycle Cooling Water Program since the applicant's open-cycle cooling water source is the Atlantic Ocean, and the program focuses on aging management of components in the ocean water environment. The applicant further stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is the appropriate AMP for this environment and crediting this AMP is consistent with item VII.E5.AP-270 of the GALL Report, Revision 2, for which GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," is recommended to manage loss of material due to general, pitting, and crevice corrosion for steel and stainless steel piping, piping components, and piping elements exposed to raw water.

The staff finds the applicant's response acceptable because potable water is neither treated water nor raw water from the ultimate heat sink. Additionally, the GALL Report identifies the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program as appropriate for an internal environment (such as indoor uncontrolled air, condensation, and steam) that is not included in other AMPs for loss of material. Also, the AMP includes periodic visual inspections with a frequency that is informed by inspection results to provide reasonable assurance that component degradation will be detected prior to loss of intended function. The staff's concern described in RAI 3.4.2.2-1 is resolved.

The staff also noted that fouling was excluded as an aging mechanism. By letter dated January 21, 2011, the staff also issued RAI 3.4.2.2-2 requesting that the applicant justify why fouling in steel and gray cast iron components exposed to raw water was excluded as an aging mechanism.

In its response dated February 18, 2011, the applicant stated that fouling and loss of material due to fouling is not expected to occur in the potable water or drinking water. The applicant also stated that the levels of total dissolved solids in the Town of Seabrook's drinking water are periodically monitored, which are less than the maximum total dissolved solids level recommended by the Environmental Protection Agency. The applicant further stated that a review of the plant operating experience showed no evidence of fouling and loss of material due to fouling in the portable water environment.

The staff finds the applicant's response acceptable because the inspections to be performed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for loss of material due to corrosion are the same as those to identify loss of material due to fouling. The plant operating experience supports the applicant's determination that loss of material due to fouling in steel and gray cast iron components exposed to portable water is not a potential aging mechanism. The staff's concern described in RAI 3.4.2.2-2 is resolved.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff finds that the applicant met the further evaluation criteria, and the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable because the program uses periodic visual inspections during maintenance or surveillance activities to identify the presence of corrosion by inspecting for discoloration and surface irregularities such as rust, scale or deposits, and surface pitting. These visual inspections can detect the aging effect of loss of material prior to the loss of component-intended function, and inspection results will be reviewed to ensure that the number of locations and inspection intervals are appropriate.

Based on the program identified above, the staff concludes that the applicant's program meets SRP-LR Section 3.4.2.2.3 criteria. For those items that apply to LRA Section 3.4.2.2.3, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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).

3.4.2.2.4 Reduction of Heat Transfer Due to Fouling

The staff reviewed LRA Section 3.4.2.2.4 against the following criteria in SRP-LR Section 3.4.2.2.4:

(1) LRA Section 3.4.2.2.4.1, is associated with LRA Table 3.4.1, item 3.4.1-9, and addresses stainless steel and copper heat exchanger tubes exposed to treated water, which are being managed for reduction of heat transfer due to fouling by the Water Chemistry and the One-Time Inspection Programs. The criteria in SRP-LR Section 3.4.2.2.4, item 1, state that reduction of heat transfer due to fouling may occur for stainless steel and copper-alloy heat exchanger tubes exposed to treated water. The SRP-LR also states that although the existing AMP relies on control of water chemistry to manage this aging effect, the control of water chemistry may not always have been adequate to preclude fouling. The SRP-LR recommends that the effectiveness of the Water Chemistry Control Program be confirmed and states that a one-time inspection is an acceptable verification method.

The staff's evaluations of the applicant's Water Chemistry and the One-Time Inspection Programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. In its review of components associated with item 3.4.1-9, the staff finds that the applicant met the further evaluation criteria. Additionally, the applicant's proposal to manage aging using the specified programs is acceptable because the Water Chemistry Program includes control of detrimental contaminants below the levels known to cause cracking, and the One-Time Inspection Program will verify the effectiveness of the chemistry controls by inspecting a sample of similar components exposed to the same environment.

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 items that apply to LRA Section 3.4.2.2.4.1, the staff determined that the LRA is consistent with the GALL

Report, and the applicant 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, is associated with LRA Table 3.4.1, item 3.4.1-10, and addresses steel, stainless steel and copper-alloy heat exchanger tubes exposed to lubricating oil, which are being managed for reduction of heat transfer due to fouling by the Lubricating Oil Analysis and One-Time Inspection Programs. The criteria in SRP-LR Section 3.4.2.2.4, item 2, state that reduction of heat transfer due to fouling may occur in steel, stainless steel, and copper-alloy heat exchanger tubes exposed to lubricating oil. The SRP-LR also states that existing AMP controls lube oil chemistry to mitigate this aging effect, and the effectiveness should be confirmed because the control of lube oil chemistry may not be fully effective in precluding fouling. The SRP-LR further states that a one-time inspection of selected components at susceptible locations is an acceptable method to verify the program's effectiveness. The applicant addressed the further evaluation criteria of the SRP-LR by stating that it will implement the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of heat transfer due to fouling in the feedwater system.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. In its review of components associated with item 3.4.1-10, the staff finds that the applicant met the further review criteria. Additionally, the applicant's proposal to manage aging using the specified AMPs acceptable because the Lubricating Oil Analysis Program includes periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, and the One-Time Inspection Program will verify the effectiveness of the Lubricating Oil Analysis Program to manage this aging effect.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.4, item 2, criteria. For those items that apply to LRA Section 3.4.2.2.4.2, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 following criteria in SRP-LR Section 3.4.2.2.5:

(1) LRA Section 3.4.2.2.5.1 is associated with LRA Table 3.4.1, item 3.4.1-11, and addresses buried steel (with or without coating or wrapping) piping, piping components, piping elements, and tanks exposed to soil, which are being managed for loss of material due to general, pitting, crevice, and MIC by the Buried Piping and Tanks Inspection Program. The criteria in SRP-LR Section 3.4.2.2.5, item 1, state that the loss of material due to general, pitting, crevice, and MIC could occur for buried steel (with or without coating or wrapping) piping, piping components, piping elements, and tanks exposed to soil environment. The SRP-LR also states that the Buried Piping and Tanks Inspection Program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material aging effect. The

applicant addressed the further evaluation criteria of the SRP-LR by stating that the Buried Piping and Tanks Inspection Program will use external coatings and wrappings on buried piping as well as periodic inspections to determine loss of material. The staff noted that the applicant stated, in LRA Section B.2.1-22 under the "detection of aging effects" program element, that inspections locations would be, in part, based on areas with a history of corrosion problems.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.3.1. In its review of components associated with LRA Table 3.4.1, item 3.4.1-11, the staff finds that the applicant met the further evaluation criteria, and the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program is acceptable for the following reasons:

- The program includes preventive actions, such as external coatings and wrappings installed to industry standard practices and backfill that will not damage the piping or coatings, and some systems are protected by a cathodic protection system.
- Periodic visual inspections will be performed starting 10 years prior to the period of extended operation and extend into both 10-year periods during the period of extended operation to ensure that coatings remain intact or uncoated piping has not degraded.
- Plant-specific operating experience will be used to inform inspection locations.
- Alternatives to direct visual inspection such as pressure tests or ultrasonic inspections are capable of detecting piping degradation.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.5, item 1, criteria. For those items that apply to LRA Section 3.4.2.2.5.1, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 3.4.2.2.5.2, is associated with LRA Table 3.4.1, item 3.4.1-12, and addresses loss of material due to general, pitting, crevice, and MIC in steel heat exchanger components exposed to lubricating oil. The applicant stated that this item is not applicable because there are no steel heat exchanger components exposed to lubricating oil in the steam and power conversion systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and confirmed that no in-scope steel heat exchanger components exposed to lubricating oil are present in the steam and power conversion systems; therefore, it finds the applicant's claim acceptable.

Based on the above, the staff concludes that SRP-LR Section 3.4.2.2.5, item 2, criteria do not apply.

3.4.2.2.6 Cracking Due to Stress Corrosion Cracking

LRA Section 3.4.2.2.6, associated with LRA Table 3.4.1, items 3.4.1-13 and 3.4.1-14, addresses stainless steel piping components exposed to treated water greater than 140 °F (60 °C), which are being managed for cracking due to SCC by the Water Chemistry Program and the One-Time Inspection Program. The criteria in SRP-LR Section 3.4.2.2.6 states that cracking due to SCC could occur for stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water greater than 140 °F (60 °C). The SRP-LR also states that cracking due to SCC could occur 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 primary water chemistry. In addition, the SRP-LR states that high concentrations of impurities in crevices and locations of stagnant flow conditions could cause SCC; therefore, the GALL Report recommends that this aging issue be managed by a One-Time Inspection Program to verify the effectiveness of the Water Chemistry Control Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry Program effectiveness will be confirmed by the One-Time Inspection Program. The applicant also stated that, for item 3.4.1-13, the applicability of the item is limited to BWRs; therefore, the item is not applicable to this LRA. In its review, the staff performed a search of the SRP-LR and confirmed that item 3.4.1-13 is only applicable for BWR plants.

The staff's evaluations of the applicant's Water Chemistry Program and the One-Time Inspection Program are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. In its review of components associated with item 3.4.1-14, the staff finds that the applicant met the further evaluation criteria, and the applicant's proposal to manage aging using the Water Chemistry Program and the One-Time Inspection Program is acceptable for the following reasons:

- The Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate the environmental effect on the aging.
- The Water Chemistry Program also takes corrective actions if the parameters exceed the limits.
- The One-Time Inspection will be used to confirm the effectiveness of the Water Chemistry Program consistent with the GALL Report.

Based on the program identified above, the staff concludes that the applicant's program meets SRP-LR Section 3.4.2.2.6 criteria. For those items that apply to LRA Section 3.4.2.2.6, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 following criteria in SRP-LR Section 3.4.2.2.7:

(1) LRA Section 3.4.2.2.7.1, is associated with LRA Table 3.4.1, items 3.4.1-6 (stainless steel tanks only), 3.4.1-15, and 3.4.1-16, and addresses aluminum, copper alloy, and stainless steel piping, piping components, piping elements, and stainless steel tanks, and heat exchanger components 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 criteria in SRP-LR Section 3.4.2.2.7, item 1, state 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 control of water chemistry to mitigate degradation, and a one-time inspection of select components at susceptible locations is an acceptable method to determine if an aging effect does not occur or progresses very slowly such that the component's intended function will be maintained during the period of extended operation. The applicant addressed the further evaluation criteria of the SRP-LR by stating that loss of material due to pitting and crevice corrosion of stainless steel piping, heat exchanger components, and tanks, and copper-alloy piping, heat exchanger components, and heater coils exposed to treated water will be managed by the Water Chemistry and One-Time Inspection Programs.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, 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 that the applicant met the further evaluation criteria. The applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection Programs is acceptable because the Water Chemistry Program uses chemical sampling and corrective actions to ensure that impurities are minimized to reduce aging due to loss of material. Additionally, the One-Time Inspection Program will perform a one-time inspection of select components to verify the effectiveness of the Water Chemistry Program for managing the aging effects of loss of material.

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 items that apply to LRA Section 3.4.2.2.7.1, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 3.4.2.2.7.2 is associated with LRA Table 3.4.1, item 3.4.1-17, and addresses stainless steel piping, piping components, and piping elements exposed to soil, which are being managed for loss of material due to pitting and crevice corrosion by the Buried Piping and Tanks Inspection Program. The criteria in SRP-LR Section 3.4.2.2.7, item 2, states that the loss of material due to pitting and crevice corrosion could occur for stainless steel piping, piping components, and piping elements exposed to soil environment. The SRP-LR also states that a plant-specific AMP will be used to manage the loss of material aging effect. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Buried Piping and Tanks Inspection Program will use external coatings and wrappings on buried piping as well as periodic inspections to determine loss of material.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.3.1. In its review of components associated with LRA Table 3.4.1, item 3.4.1-17, the staff finds that the applicant met the further evaluation criteria, and the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program is acceptable for the following reasons:

- The program includes preventive actions, such as external coatings and wrappings installed to industry standard practices and backfill that will not damage the piping or coatings, and some systems are protected by a cathodic protection system.

- Periodic visual inspections will be performed starting 10 years prior to the period of extended operation and extend into both 10-year periods during the period of extended operation to ensure that coatings remain intact or uncoated piping has not degraded.
- Plant-specific operating experience will be used to inform inspection locations.
- Alternatives to direct visual inspection, such as pressure tests or ultrasonic inspections, are capable of detecting piping degradation.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.7, item 2, criteria. For those items that apply to LRA Section 3.4.2.2.7.2, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 3.4.2.2.7.3, referenced by LRA Table 3.4.1, item 3.4.1-18, addresses copper-alloy piping, piping components, and piping elements exposed to lubricating oil, 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 criteria of the SRP-LR by stating that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program to manage loss of material due to pitting and crevice corrosion through examination of susceptible locations in copper-alloy piping, piping components, and copper-alloy heat exchanger components exposed to lubricating oil.

The staff reviewed LRA Section 3.4.2.2.7.3 against the criteria in SRP-LR Section 3.4.2.2.7, item 3, 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 AMP 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. The SRP-LR further states that control of lube oil contaminants may not always have been adequate to preclude corrosion; therefore, the effectiveness of lubricating oil contaminant control should be confirmed to ensure that corrosion does not occur. The SRP-LR also states that the GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the Lubricating Oil Analysis Program. The GALL Report also states that a one-time inspection of selected 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's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. In its review of components associated with item 3.4.1-18, the staff finds the applicant's proposal to manage aging using the One-Time Inspection Program to verify the effectiveness of the Lubricating Oil Analysis Program acceptable because the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report. Additionally, the applicant stated that the One-Time Inspection Program will be used to examine copper-alloy piping, piping components, and copper-alloy heat exchanger components to verify the effectiveness of the Lubricating Oil Analysis Program. This satisfies the acceptance criteria in SRP-LR Section 3.4.2.2.7, item 3; therefore, the applicant's AMR is consistent with the GALL Report.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.7, item 3, criteria. For those items that apply to LRA Section 3.4.2.2.7.3, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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 is associated with LRA Table 3.4.1, item 3.4.1-19, and addresses stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil, which are being managed for reduction of heat transfer due to fouling by the Lubricating Oil Analysis and the One-Time Inspection Programs. The criteria in SRP-LR Section 3.4.2.2.8 state that loss of material due to pitting, crevice, and MIC could occur in stainless steel piping components and heat exchanger components exposed to lubricating oil and that the existing AMP controls lube oil chemistry to maintain contaminants within limits that are not conducive to corrosion. The SRP-LR also states that the effectiveness of the program should be confirmed because control of lube oil chemistry may not have precluded corrosion, and a one-time inspection of selected components at susceptible locations is an acceptable verification method.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection Programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. In its review of components associated with item 3.4.1-19, the staff finds the applicant met the further evaluation review criteria. The staff finds the applicant's proposal to manage aging using the specified AMPs acceptable because the Lubricating Oil Analysis Program maintains contaminants within acceptable limits, and the One-Time Inspection Program will verify the effectiveness of the Lubricating Oil Analysis Program to manage this aging effect.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.8 criteria. For those items that apply to LRA Section 3.4.2.2.8, the staff determined that the LRA is consistent with the GALL Report. The applicant 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).

3.4.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Galvanic Corrosion

LRA Section 3.4.2.2.9 is associated with LRA Table 3.4.1, item 3.4.1-5, and addresses loss of material due to general, pitting, crevice, and galvanic corrosion in steel heat exchanger components exposed to treated water. The applicant stated that this item is not applicable because there are no steel heat exchanger components exposed to treated water in the steam and power conversion systems. The staff reviewed LRA Section 3.4 and noted that, contrary to the applicant's statement, there are steel heat exchanger components exposed to treated water in the steam and power conversion systems. The staff noted, however, the applicant aligned these heat exchanger components to LRA Table 3.4.1, item 3.4.1-3, which addresses the same aging effect for similar components in treated water in PWRs. The staff also noted that these items are the subject of SRP-LR Section 3.4.2.2.2, item 1, and the further evaluation criteria are identical. The staff further noted that SRP-LR item 3.4.1-5 is for BWR components; therefore, it finds the applicant's claim, that this item is not applicable, acceptable.

Based on the above, the staff concludes that SRP-LR Section 3.4.2.2.9 criteria do not apply.

3.4.2.2.10 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.4.2.3 Aging Management Review Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.4.2-1 through 3.4.2-8, 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 3.4.2-1 through 3.4.2-8, via Notes F–J, the applicant indicated which combinations of component type, material, environment, and AERM do not correspond to an 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 item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR 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 item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the 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 if the applicant 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.

3.4.2.3.1 Auxiliary Steam System—Summary of Aging Management Review—LRA Table 3.4.2-1

The staff reviewed LRA Table 3.4.2-1, which summarizes the results of AMR evaluations for the auxiliary steam system component groups.

In LRA Table 3.4.2-1, the applicant stated that the copper-alloy greater than 15 percent zinc valve bodies exposed to steam are being managed for loss of material by the Water Chemistry Program and One-Time Inspection Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though copper alloys, greater than 15 percent zinc, exposed to steam are not specifically addressed in the GALL Report, Chapter V of the GALL Report indicates that copper alloys exposed to aqueous environments are susceptible to loss of material.

The staff's evaluation of the applicant's Water Chemistry Program and One-Time Inspection Program is documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. The staff notes that the Water Chemistry Program relies upon periodic monitoring and control of detrimental contaminants in the water to manage loss of material. The staff also notes that the One-Time Inspection Program uses non-destructive examination methods to verify the effectiveness of the Water Chemistry Program. The staff finds the applicant's proposal to manage aging using the Water Chemistry Program and One-Time Inspection Program acceptable because the maintenance of water chemistry will prevent the buildup of impurities that could lead to a loss of material, and the non-destructive examinations will verify the effectiveness of the Water Chemistry Program.

In LRA Tables 3.4.2-1 and 3.4.2-3, the applicant stated that the gray cast iron and copper-alloy (greater than 15 percent zinc) components exposed to steam (internal) are being managed for loss of material by the Selective Leaching of Materials Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. For each AMR item that identifies selective leaching as an aging effect, there is an additional item that identifies loss of material (e.g., pitting, crevice corrosion) as an aging effect that will be managed by the Water Chemistry and One-Time Inspection Programs, or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program. Therefore, other loss of material aging effects will be managed. The staff noted that the GALL Report Table IX.C states that copper alloy (greater than 15 percent zinc) is susceptible to SCC. However, this aging effect would not be expected to occur in a steam environment because there are no compounds (e.g., ammonia) that cause SCC in this material ("Conditions Contributing to Underground Copper Corrosion," *American Water Works Association Journal*, August 1984).

The staff's evaluation of the applicant's Selective Leaching of Materials Program is documented in SER Section 3.0.3.2.12. The staff finds the applicant's proposal to manage aging using the Selective Leaching of Materials Program acceptable because the proposed program includes visual inspections and mechanical examination techniques that will determine whether loss of material due to selective leaching is occurring.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.4.2.3.2 Auxiliary Steam Condensate System—Summary of Aging Management Review—LRA Table 3.4.2-2

The staff reviewed LRA Table 3.4.2-2, which summarizes the results of AMR evaluations for the auxiliary steam condensate system component groups.

The staff's review did not find any items indicating plant-specific notes F–J, whereby the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report.

The staff's evaluation of the items with notes A–E is documented in SER Section 3.4.2.1.

3.4.2.3.3 Auxiliary Steam Heating System—Summary of Aging Management Review—LRA Table 3.4.2-3

The staff reviewed LRA Table 3.4.2-3, which summarizes the results of AMR evaluations for the auxiliary steam heating system component groups.

In LRA Table 3.4.2-3, the applicant stated that steel, stainless steel, and gray cast iron piping components and steel and stainless steel heat exchanger components exposed to steam are being managed for loss of material by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR items cite generic note G and plant-specific note 1, which states that the environment is potable water converted to steam.

The staff noted that in the LRA received June 1, 2010, the AMR items originally cited generic note E and referenced LRA Table 3.4.1, item 3.4.1-37, which addressed steel and stainless steel piping and heat exchanger components exposed to steam being managed for loss of material due to general (steel only), pitting, and crevice corrosion. For these items, the GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry Program," to ensure that these aging effects are adequately managed. In its review of components associated with item 3.4.1-37, for which the applicant cited generic note E, the staff also noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage the aging of steel and stainless steel components through the use of opportunistic visual inspections. By letter dated January 5, 2011, the staff issued RAI 3.4.2.3-1 requesting that the applicant justify how loss of material in steel and stainless steel components exposed to steam will be managed in the absence of preventive actions, including chemical sampling and corrective actions, in light of the potential infrequent inspections that may occur due to managing these components with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

In its response dated February 3, 2011, the applicant stated that the steam environment listed in Table 3.4.2-3 for the auxiliary steam heating system components is potable water converted to steam, which is not the same steam environment listed in item 3.4.1-37. The applicant also stated that the PWR secondary plant Water Chemistry Program is not applicable to potable water; therefore, item 3.4.1-37 should not have been selected for steam environment converted from potable water. The AMR items in Table 3.4.2-3 were revised to cite generic note G. The applicant further stated that the selection of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is the appropriate AMP for this environment. It is consistent with item VII.E5.AP-270 of the GALL Report, Revision 2, for which GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," is recommended to manage loss of material due to general (steel only), pitting, and crevice corrosion for steel and stainless steel piping, piping components, and piping elements exposed to raw water (potable).

The staff finds the applicant's response acceptable because steam generated from untreated water is not an environment in the GALL Report, and the GALL Report identifies the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program as appropriate for an internal environment, such as steam, that is not included in other AMPs for loss of material. The AMP includes periodic visual inspections that are capable of detecting loss of material, with a frequency that is informed by inspection results to provide reasonable assurance that component degradation will be detected prior to loss of intended function. The staff's concern described in RAI 3.4.2.3-1 is resolved.

The staff noted that GALL Report Tables IX.C and IX.E state that the applicable aging effects for gray cast iron, steel, and stainless steel include loss of material, cracking (stainless steel only), and reduction in heat transfer. The staff also noted that although the GALL Report does not specifically address aging in potable water converted to steam, the applicable aging effects would be expected to be consistent with those listed in Tables IX.C and IX.E. The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because the applicant addressed the other applicable aging effects, cracking and reduction of heat transfer, in Table 3.4.2-3.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. 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 the program uses periodic visual inspections during maintenance or surveillance activities, which are capable of detecting the presence of corrosion by inspecting for localized discoloration and surface irregularities such as rust, scale or deposits, and surface pitting. Additionally, inspection results will be reviewed to ensure that the number of locations and inspection intervals are appropriate.

In LRA Table 3.4.2-3, the applicant stated that aluminum heat exchanger components exposed to air-indoor uncontrolled (external) are being managed for reduction in heat transfer by the External Surfaces Monitoring Program. The AMR item cites generic note F.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. The GALL Report, item V.F-2, states that aluminum components exposed to air have no aging effects requiring management. Also, the components of interest function in a capacity to provide heat transfer; therefore, any accumulation of dirt, debris, or scale could prevent the component from performing its intended function, which is addressed in this AMR item.

The staff's evaluation of the applicant's Inspection of External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the program uses periodic visual inspections that would identify corrosion discoloration and accumulation of dirt, scale, or debris indicative of fouling; thus, it would detect any reduction in heat transfer prior to loss of component-intended function.

The staff's evaluation for gray cast iron and copper-alloy (greater than 15 percent zinc) components, exposed to stream (internal) and being managed for loss of material by the Selective Leaching of Materials Program citing generic note G, is documented in SER Section 3.4.2.3.1.

In LRA Table 3.4.2-3, the applicant stated that steel, stainless steel, and gray cast iron piping components and steel and stainless steel heat exchanger components exposed to steam are being managed for loss of material by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR items cite generic note G and plant-specific note 1, which states that the environment is potable water converted to steam.

The staff noted that in the LRA received June 1, 2010, the AMR items originally cited generic note E and referenced LRA Table 3.4.1, item 3.4.1-37, which addressed steel and stainless steel piping and heat exchanger components exposed to steam being managed for loss of material due to general (steel only), pitting, and crevice corrosion. For these items, the GALL

Report recommends GALL Report AMP XI.M2, “Water Chemistry,” to ensure that these aging effects are adequately managed. In its review of components associated with item 3.4.1-37, for which the applicant cited generic note E, the staff also noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage the aging of steel and stainless steel components through the use of opportunistic visual inspections. By letter dated January 5, 2011, the staff issued RAI 3.4.2.3-1 requesting that the applicant justify how loss of material in steel and stainless steel components exposed to steam will be managed in the absence of preventive actions, including chemical sampling and corrective actions, in light of the potential infrequent inspections that may occur due to managing these components with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

In its response dated February 3, 2011, the applicant stated that the steam environment listed in Table 3.4.2-3 for the auxiliary steam heating system components is potable water converted to steam, which is not the same steam environment listed in item 3.4.1-37. The applicant also stated that the PWR secondary plant Water Chemistry Program is not applicable to potable water; therefore, item 3.4.1-37 should not have been selected for steam environment converted from potable water. The AMR items in Table 3.4.2-3 were revised from generic note E and plant-specific note 1 to generic note G and plant-specific note 1. The applicant further stated that the selection of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is the appropriate AMP for this environment. It is consistent with item VII.E5.AP-270 of the GALL Report, Revision 2, for which GALL Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” is recommended to manage loss of material due to general (steel only), pitting, and crevice corrosion for steel and stainless steel piping, piping components, and piping elements exposed to raw water (potable).

The staff finds the applicant’s response acceptable because steam generated from untreated water is not an environment in the GALL Report, and the GALL Report identifies the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program as appropriate for an internal environment, such as steam, that is not included in other AMPs for loss of material. The AMP includes periodic visual inspections that are capable of detecting loss of material, with a frequency that is informed by inspection results to provide reasonable assurance that component degradation will be detected prior to loss of intended function. The staff’s concern described in RAI 3.4.2.3-1 is resolved.

The staff noted that GALL Report Tables IX.C and IX.E state that the applicable aging effects for gray cast iron, steel, and stainless steel include loss of material, cracking (stainless steel only), and reduction in heat transfer. The staff also noted that although the GALL Report does not specifically address aging in potable water converted to steam, the applicable aging effects would be expected to be consistent with those listed in Tables IX.C and IX.E. The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because the applicant addressed the other applicable aging effects, cracking, and reduction of heat transfer in Table 3.4.2-3.

The staff’s evaluation of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. 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 the program uses periodic visual inspections during maintenance or surveillance activities, which are capable of detecting the presence of corrosion by inspecting for localized discoloration and surface irregularities such as rust, scale or deposits, and surface pitting. Additionally, inspection results will be reviewed to ensure that the number of locations and inspection intervals are appropriate.

In LRA Table 3.4.2-3, the applicant stated that stainless steel heat exchanger components, exposed to steam (internal or external) are being managed for reduction of heat transfer with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because the GALL Report, Table IX.B, states that heat exchanger components are susceptible to reduction of heat transfer, which is addressed in the AMR. The staff noted that the material of the component, stainless steel, is also susceptible to loss of material due to pitting and crevice corrosion and cracking due to SCC aging effects, both of which are addressed in other AMR items.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable. The program includes periodic visual inspections performed during maintenance and surveillance activities, which can identify localized discoloration and surface irregularities such as rust, scale or deposits, and surface pitting to determine if material degradation is occurring that could result in loss of the component-intended function.

In LRA Table 3.4.2-3, the applicant stated that copper alloy and copper alloy greater than 15 percent zinc piping, fittings, and valve bodies exposed to steam (internal) are being managed for loss of material due to general, pitting, and crevice corrosion with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Although copper exposed to steam is not specifically addressed in the GALL Report, Table IX.C of the GALL Report states that copper alloys and copper alloys with greater than 15 percent zinc are susceptible to loss of material due to pitting and crevice corrosion. The GALL Report, Table IX.C, also states that copper alloys with greater than 15 percent zinc are susceptible to selective leaching and SCC. The staff noted that the applicant addressed selective leaching in another AMR item. The staff also noted that copper alloys with greater than 15 percent zinc are only susceptible to SCC in the presence of ammonia (*Handbook of Corrosion Data*, 1995), and the staff did not find any evidence that ammonia is present in the auxiliary steam heating system. Therefore, the only aging effects of concern are loss of material due to pitting and crevice corrosion and loss of material due to selective leaching, which are addressed in the AMR.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable. The program includes periodic visual inspections performed during maintenance and surveillance activities, which can identify localized discoloration and surface irregularities such as rust, scale or deposits, and surface pitting to determine if material degradation is occurring that could result in a loss of component-intended function.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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 Circulating Water System—Summary of Aging Management Review—LRA Table 3.4.2-4

The staff reviewed LRA Table 3.4.2-4, which summarizes the results of AMR evaluations for the circulating water system component groups.

In LRA Table 3.4.2-4, the applicant stated that the steel bolting exposed to condensation is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though steel bolting exposed to condensation is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, Table IX.C of the GALL Report states that steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to general, pitting, and crevice corrosion. The staff noted that the applicant addressed loss of material in additional items for each of these components; therefore, the aging effect of concern is loss of preload, which is addressed in the AMR.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload of steel bolting exposed to condensation uncontrolled in the steam and power conversion system, the GALL Report has items for loss of preload of other material bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload. Additionally, the program inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

In LRA Table 3.4.2-4, the applicant stated that nickel alloy and copper alloy with greater than 15 percent zinc valve body and nickel-alloy piping and fittings and thermowell exposed to condensation (external) are being managed for loss of material by the External Surfaces Monitoring Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. While nickel-alloy components exposed to condensation (external) are not specifically addressed in the GALL Report, item VII.C1-13 states that nickel alloys exposed to raw water are susceptible to loss of material, which is addressed in the AMR item. Separately, the GALL Report, item VII.F1-16 states that copper-alloy components exposed to condensation are susceptible to loss of material. Copper alloy with greater than 15 percent zinc components is a subset of copper-alloy components, and the GALL Report states that copper alloy with greater than 15 percent zinc components is susceptible to selective leaching. By letter dated February 24, 2011, the staff issued RAI 3.4.2.3.4-1 requesting that the applicant clarify if the copper alloy with greater than 15 percent zinc is managed for selective leaching or not. The staff also asked the applicant to state the AMP and inspection method(s) being used to manage the loss of material if it is determined that the copper alloy with greater than 15 percent zinc should be managed for selective leaching.

In its response dated March 22, 2011, the applicant stated that selective leaching has been added as an aging mechanism for copper alloy greater than 15 percent zinc components exposed to internal or external condensation environment. In addition, the applicant stated the following:

- Selective leaching has also been added as an aging mechanism for gray cast iron components exposed to internal or external condensation environment.
- Affected LRA Tables 3.3.2-4, 3.3.2-9, 3.3.2-12, 3.3.2-15, 3.3.2-19, 3.3.2-20, 3.3.2-36, 3.3.2-37, 3.3.2-44, and 3.4.2-4 have been updated to reflect the addition.
- The program description language in LRA Appendices A (Section A.2.1.21) and B (Section B.2.1.21) has been modified to include condensation as an environment managed by the Selective Leaching of Materials Program.

The staff finds the applicant’s response acceptable because the applicant included selective leaching as an aging mechanism for copper alloy greater than 15 percent zinc components exposed to internal or external condensation environment, and the Selective Leaching of Materials Program will be used to manage the effects of aging. The staff’s concern described in RAI 3.4.2.3.4-1 is resolved.

The staff’s evaluations of the applicant’s Selective Leaching of Materials and External Surfaces Monitoring Programs are documented in SER Sections 3.0.3.2.12 and 3.0.3.2.14, respectively. The staff finds the applicant’s proposal to manage aging using the External Surfaces Monitoring and Selective Leaching of Materials Programs acceptable because the External Surfaces Monitoring Program uses periodic visual inspections. Additionally, the Selective Leaching of Materials Program uses a one-time visual inspection and hardness measurement of selective set of sample components, which would detect loss of material prior to loss of component-intended function.

In LRA Table 3.4.2-4, the applicant stated that the elastomer expansion joints exposed to condensation (external) are being managed for hardening and loss of strength by the External Surfaces Monitoring Program. The AMR item cites generic note H.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. The GALL Report, Table IX.C, indicates that elastomers are susceptible to hardening and loss of strength at temperatures over 95 °F (35 °C), and the environment of interest, condensation, can be in a temperature range in which elastomers are susceptible to hardening and loss of strength, which is addressed in the AMR.

The staff’s evaluation of the applicant’s External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff noted that the applicant’s program includes non-visual examinations, such as scratching, to determine if scale or residues are present or determine if there is a breakdown of material, bending or folding of the elastomer to detect cracking that initiates at the surface, stretching and pressing to determine the resistance of the material to hardening effects, and pressing to gauge the materials resiliency. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the program uses periodic visual inspections as well as non-visual tactile examinations, which are capable of detecting hardening and loss of strength.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.4.2.3.5 Condensate System—Summary of Aging Management Review—LRA Table 3.4.2-5

The staff reviewed LRA Table 3.4.2-5, which summarizes the results of AMR evaluations for the condensate system component groups.

In LRA Tables 3.4.2-5, 3.4.2-6, 3.4.2-7, and 3.4.2-8, the applicant stated that the stainless steel bolting exposed to air-indoor uncontrolled is being managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though stainless steel bolting exposed to air-indoor uncontrolled is not specifically addressed in the GALL Report, Table IX.E of the GALL Report states that loss of preload can occur independent of environmental conditions because it can be caused by thermal or mechanical effects. Additionally, Table IX.C of the GALL Report states that stainless steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion and cracking due to SCC. The staff noted that the environment of interest, air-indoor, would not induce SCC or loss of material in stainless steel material because stainless steel is inherently resistant to corrosion in the air-indoor environment. Therefore, the aging effect of concern is loss of preload, which is addressed in the AMR.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.1.7. While there is no AMR for loss of preload of stainless steel bolting exposed to air-indoor uncontrolled in the steam and power conversion system, the GALL Report has items for loss of preload of other material bolting managed by the Bolting Integrity Program. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the Bolting Integrity Program conducts bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload. The program also inspects for leakage and loose or missing nuts, which verify that the aging effect, loss of preload, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

In LRA Table 3.4.2-5, the applicant stated that the stainless steel tanks exposed to air-outdoor (external) are being managed for loss of material by the External Surfaces Monitoring Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination. Even though stainless steel exposed to air-outdoor (external) is not specifically addressed in the GALL Report, Table IX.C of the GALL Report states that stainless steels are susceptible loss of material and cracking due to SCC. The staff noted that the environment of interest, air-outdoor (external), would be expected to contain higher levels of chlorides due to the site's relative proximity to the ocean, which are known to induce SCC. By letter dated February 24, 2011, the staff issued RAI 3.3-1 requesting that the applicant provide additional information on why atmospheric chloride-induced SCC is not considered to be an applicable aging effect for stainless steel components exposed to outdoor-air. The staff also asked the applicant to explain how SCC will be managed if it is determined to be an applicable aging affect.

In its response dated March 22, 2011, the applicant stated that SCC has been added as an aging mechanism for stainless steel components exposed to air-outdoor environment. The applicant added a new item to manage cracking by the External Surfaces Monitoring Program. The staff finds the applicant's response acceptable because the applicant modified the LRA to include SCC as an applicable aging effect for stainless steel components exposed to outdoor-air containing high levels of chloride and include SCC as an aging effect to be managed by the External Surfaces Monitoring Program, which includes visual inspection that is a capable technique to detect SCC. The staff's concern described in RAI 3.3-1 is resolved.

The staff's evaluation of the applicant's Inspection of External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.14. The staff finds that the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the program uses periodic visual inspections that would detect loss of material and detect SCC prior to loss of component-intended function.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.4.2.3.6 Feedwater System—Summary of Aging Management Review—LRA Table 3.4.2-6

The staff reviewed LRA Table 3.4.2-6, which summarizes the results of AMR evaluations for the feedwater system component groups.

In LRA Tables 3.4.2-6 and 3.4.2-7, the applicant stated that the aluminum instrumentation element components exposed to lubricating oil (internal) are being managed for loss of material by the Lubricating Oil Analysis Program, as augmented by the One-Time Inspection Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because, as stated in the *ASM Handbook*, ASM International, 2005, aluminum is a corrosion-resistant material. For aluminum instrumentation element components internally exposed to oil, the applicant identified the appropriate aging effects (i.e., loss of material). This aging effect is managed by the Lubricating Oil Analysis Program, as augmented by the One-Time Inspection Program. The staff's evaluations of the applicant's Lubricating Oil Analysis Program and the One-Time Inspection Program are documented in SER Sections 3.0.3.2.16 and 3.0.3.1.8, respectively. The Lubricating Oil Analysis Program performs oil condition monitoring activities to manage the aging effects of loss of material due to galvanic, general, pitting, crevice, and MIC, fouling, and heat transfer degradation due to fouling. The One-Time Inspection Program visually inspects components for loss of material.

The staff finds the applicant's proposal to manage aging using the Lubricating Oil Analysis Program, as augmented by the One-Time Inspection Program, acceptable because the Lubricating Oil Analysis Program monitors for contaminants that could cause corrosion and for degradation of the oil that could be caused by corrosion products. This analysis is supplemented by the One-Time Inspection Program, which uses visual examinations and other examination techniques to inspect for the loss of material in areas where the most severe aging effects would be expected to occur.

The staff's evaluation for stainless steel bolting, exposed to air-indoor uncontrolled and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.4.2.3.5.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.4.2.3.7 Main Steam System—Summary of Aging Management Review—LRA Table 3.4.2-7

The staff reviewed LRA Table 3.4.2-7, which summarizes the results of AMR evaluations for the main steam system component groups.

In LRA Table 3.4.2-7, the applicant stated that stainless steel valve bodies, piping, fittings, and orifices exposed to air-outdoor (internal) are being managed for loss of material due to general, pitting, and crevice corrosion by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and noted that, even though stainless steel valve bodies, piping, fittings, and orifices exposed to air-outdoor are not specifically addressed in the GALL Report, Table IX.C of the GALL Report states that stainless steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion and cracking due to SCC. The staff noted that given the plant's proximity to the ocean, stainless steel components exposed to the air-outdoor (internal) environment would be susceptible to cracking due to SCC. However, the staff noted that the applicant did not identify SCC as an AERM for these components. By letter dated February 24, 2011, the staff issued RAI 3.3-1 requesting that the applicant justify its management of this material, environment, AERM, and AMP combination.

In its response dated March 22, 2011, the applicant stated that SCC has been added as an aging mechanism for stainless steel components exposed to an air-outdoor environment. The applicant added new AMR items to manage cracking using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff finds the applicant's response acceptable because the applicant modified the LRA to include cracking due to SCC as an applicable aging effect for stainless steel components exposed to outdoor air, and it will use either magnified visual inspections or ultrasonic inspections, which are capable of detecting cracking. The staff's concern described in RAI 3.3-1 is resolved.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.15. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable for the following reasons:

- The program includes periodic visual inspections performed during maintenance and surveillance activities, which can identify localized discoloration and surface irregularities such as rust, scale or deposits, and surface pitting.
- The program includes either magnified visual inspection or ultrasonic inspection to determine if material degradation is occurring that could result in a loss of the component-intended function.

The staff's evaluation for stainless steel bolting, exposed to air-indoor uncontrolled and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.4.2.3.5.

The staff's evaluation for aluminum instrumentation element components, exposed to lubricating oil (internal) and being managed for loss of material by the Lubricating Oil Analysis Program, as augmented by the One-Time Inspection Program citing generic note G, is documented in SER Section 3.4.2.3.6.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.4.2.3.8 Steam Generator Blowdown System—Summary of Aging Management Review—LRA Table 3.4.2-8

The staff reviewed LRA Table 3.4.2-8, which summarizes the results of AMR evaluations for the steam generator blowdown system component groups.

The staff's evaluation for stainless steel bolting, exposed to air-indoor uncontrolled and being managed for loss of preload by the Bolting Integrity Program citing generic note G, is documented in SER Section 3.4.2.3.5.

In LRA Table 3.4.2-8 the applicant stated that for glass piping elements exposed to air-with borated water leakage (external) there is no aging effect and no AMP is proposed. The AMR item cites generic note G. The staff reviewed the associated item in the LRA and confirmed that no aging effect is applicable for this component, material and environment combination because the GALL Report, item V.F-9, states that for an environment of treated borated water there is no AERM and no recommended AMP, and the air with borated water leakage environment is no more severe than the treated borated water environment.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant 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).

3.4.3 Conclusion

The staff concludes that the applicant provided sufficient information to demonstrate that the effects of aging for the steam and power conversion systems 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).

3.5 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 following structures and component supports groups:

- buildings and structures within license renewal
- containment structures
- fuel handling and overhead cranes
- miscellaneous yard structures
- primary structures
- supports
- turbine building
- water control 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 CRs 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 if the applicant 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).

The staff conducted a review of the AMR items that the applicant identified as being consistent with the GALL Report 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 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 audit evaluation are documented in SER Section 3.5.2.1.

The staff also conducted a review of selected 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 conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed were appropriate for the material-environment combinations specified. The staff's evaluations are documented 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 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 structures and component supports 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
PWR concrete (reinforced and prestressed) and steel 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 nonaggressive. A plant-specific program is to be evaluated if environment is aggressive.	Yes, plant-specific, if environment is aggressive	ISI (IWL); Structures Monitoring Program	Cannot complete review until OI 3.0.3.2.18-1 is resolved (See SER Section 3.5.2.2.1)
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 applicant is to ensure proper functioning of the dewatering system through the period of extended operation	Yes, if not within the scope of the applicant's Structures Monitoring Program or a dewatering system is relied upon.	Structures Monitoring Program	Consistent with GALL Report (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
Concrete elements—foundation, sub-foundation (3.5.1-3)	Reduction in foundation strength, cracking, 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 applicant is to ensure proper functioning of the dewatering system through the period of extended operation	Yes, if not within the scope of the applicant's Structures Monitoring Program or a dewatering system is relied upon.	Not applicable—Porous concrete subfoundation is not incorporated into the design and construction of foundation	Not applicable to Seabrook (See SER Section 3.5.2.2.1)
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, plant-specific if temperature limits are exceeded	Not applicable	Not applicable to Seabrook (See SER Section 3.5.2.2.1)
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, if corrosion is significant for inaccessible areas	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.2.1)
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, if corrosion is significant for inaccessible areas	ISI (IWE) and 10 CFR Part 50, Appendix J	Consistent with GALL Report (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
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, TLAA	Not applicable	Not applicable to Seabrook (See SER Section 3.5.2.2.1)
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 10CFR 54.21(c)	Yes, TLAA	Not applicable	Not applicable to PWRs (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 10CFR 54.21(c)	Yes, TLAA.	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Consistent with GALL Report (See SER Section 3.5.2.2.1)
Stainless steel penetration sleeves, penetration bellows, dissimilar metal welds (3.5.1-10)	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J and additional appropriate examinations/ evaluations for bellows assemblies and dissimilar metal welds	Yes, detection of aging is to be evaluated	Not applicable	Not applicable to Seabrook (See SER Section 3.5.2.2.1)
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 examinations/evaluations for bellows assemblies and dissimilar metal welds	Yes, detection of aging is to be evaluated	Not applicable	Not applicable to PWRs (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 supplemented to detect fine cracks	Yes, detection of aging is to be evaluated	Not applicable	Not applicable to Seabrook (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, 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 supplemented to detect fine cracks	Yes, detection of aging is to be evaluated	Not applicable	Not applicable to PWRs (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, for inaccessible areas of plants located in moderate to severe weathering conditions.	ASME Code Subsection IWL	Consistent with GALL Report (See SER Section 3.5.2.2.1)
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 and 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, if concrete was not constructed as stated in inaccessible areas.	ASME Code Subsection IWL	Cannot complete review until OI 3.0.3.2.18-1 is resolved (See SER Section 3.5.2.2.1)
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	ISI (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 TS	No	10 CFR Part 50, Appendix J and Plant TSs surveillance testing 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
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	ISI (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 PWRs (See SER Section 3.5.2.1.1)
Steel elements—suppression chamber liner (Inner 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 PWRs (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	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Prestressed containment—tendons and anchorage components (3.5.1-22)	Loss of material due to corrosion	ISI (IWL)	No	Not applicable	Not applicable to Seabrook (See SER Section 3.5.2.1.1)
Safety-related and other structures and component supports					
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, if not within scope of the applicant's Structures Monitoring Program	Structures Monitoring Program	Cannot complete review until OI 3.0.3.2.18-1 is resolved (See SER Section 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, if not within scope of the applicant's Structures Monitoring Program	Structures Monitoring Program and Fire Protection Program	Cannot complete review until OI 3.0.3.2.18-1 is resolved (See SER Sections 3.5.2.1.6 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
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, if not within the scope of the applicant's Structures Monitoring Program	Structures Monitoring Program	Cannot complete review until OI 3.0.3.2.18-1 is resolved (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, if not within the scope of the applicant's Structures Monitoring Program or for inaccessible areas of plants located in moderate to severe weathering conditions	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, if not within the scope of the applicant's Structures Monitoring Program or concrete was not constructed as stated for inaccessible areas	Structures Monitoring Program	Cannot complete review until OI 3.0.3.2.18-1 is resolved (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 applicant is to ensure proper functioning of the dewatering system through the period of extended operation	Yes, if not within the scope of the applicant's Structures Monitoring Program or a dewatering system is relied upon	Not applicable	Not applicable to Seabrook (See SER Section 3.5.2.2.2)
Groups 1–3, 5–9—foundation (3.5.1-29)	Reduction in foundation strength, cracking, 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 applicant is to ensure proper functioning of the dewatering system through the period of extended operation	Yes, if not within the scope of the applicant's Structures Monitoring Program	Structures Monitoring Program	Not applicable to Seabrook (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, if not within the scope of the ISI or Structures Monitoring Programs	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, plant-specific, If environment is aggressive	Structures Monitoring Program	Cannot complete review until OI 3.0.3.2.18-1 is resolved (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, 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, if concrete was not constructed as stated for inaccessible areas	Structures Monitoring Program for accessible areas	Cannot complete review until OI 3.0.3.2.18-1 is resolved (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	Plant-specific	Yes, plant-specific if temperature limits are exceeded	A plant-specific AMP is to be evaluated	Not applicable to Seabrook (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. Plant-specific if environment is aggressive	Inspection of water-control structures associated with nuclear plants is integrated into the Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.5.2.1.5 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
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, for inaccessible areas of plants located in moderate to severe weathering conditions	Inspection of water-control structures associated with nuclear plants is integrated into the Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.5.2.1.2 and 3.5.2.2.2)
Group 6—all accessible and inaccessible reinforced concrete (3.5.1-36)	Cracking due to expansion/re-action 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, if concrete was not constructed as stated for inaccessible areas	Inspection of Water-control structures associated with nuclear plants is integrated into the Structures Monitoring Program	Cannot complete review until OI 3.0.3.2.18-1 is resolved (See SER Section 3.5.2.1.7 and 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, if concrete was not constructed as stated for inaccessible areas	Inspection of water-control structures associated with nuclear plants is integrated into the Structures Monitoring Program	Cannot complete review until OI 3.0.3.2.18-1 is resolved (See SER Section 3.5.2.1.6 and 3.5.2.2.2)
Groups 7, 8: Tank Liners (3.5.1-38)	Cracking due to SCC; loss of material due to pitting and crevice corrosion	Plant-specific	Yes	Not applicable	Not applicable to Seabrook (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, if not within the scope of the applicant's Structures Monitoring Program	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, if not within the scope of the applicant's Structures Monitoring Program	Structures Monitoring Program	Cannot complete review until OI 3.0.3.2.18-1 is resolved (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, if not within the scope of the applicant's Structures Monitoring Program	Not applicable	Not applicable to Seabrook (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, TLAA	Not applicable	Not applicable to Seabrook (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	Masonry Wall Program is integrated into the Structures Monitoring Program and Fire Protection Program	Consistent with GALL Report (See SER Section 3.5.2.1.8)
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	Inspection of water-control structures associated with nuclear plants is integrated into the Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.5.2.1.3)
Group 5—fuel pool liners (3.5.1-46)	Cracking due to SCC; loss of material due to pitting and crevice corrosion	Water chemistry and monitoring of spent fuel pool water level and level of fluid in the leak chase channel	No	Water Chemistry Program	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 associated with nuclear power plants. If protective coatings are relied upon to manage aging, protective coating monitoring and maintenance provisions should be included.	No	Inspection of water-control structures associated with nuclear plants is integrated into the Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.5.2.1.3)
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, Seepage	Inspection of water-control structures associated with nuclear power plants	No	Inspection of water-control structures associated with nuclear plants is integrated into the Structures Monitoring Program	Consistent with GALL Report (See SER Section 3.5.2.1.4)
Support members—welds; bolted connections; support anchorage to building structures (3.5.1-49)	Loss of material/ general, pitting, and crevice corrosion	Water chemistry and ISI (IWF)	No	Not applicable	Not applicable to PWRs (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
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	Consistent with GALL Report
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 Program (XI.M18)	No	Not applicable	Not applicable to Seabrook (See SER Section 3.5.2.1.1)
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, fatigue due to vibratory and cyclic thermal loads	Structures Monitoring Program	No	Structures Monitoring or IWF	Consistent with GALL Report (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 Code Section XI, Subsection IWF Program	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 Code Section XI, Subsection IWF Program	Consistent with GALL Report
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	Boric Acid Corrosion 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
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	Structures Monitoring or IWF	Consistent with GALL Report (See SER Section 3.5.2.1.1)
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, sustained vibratory loading	ISI (IWF)	No	Not applicable	Not applicable to Seabrook (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
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 structures and component supports groups followed any one of several approaches. One approach, documented in SER Section 3.5.2.1, 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 3.5.2.2, 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 3.5.2.3, 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 structures and component supports component groups is documented in SER Section 3.0.3.

3.5.2.1 Aging Management Review Results 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:

- ASME Code Section XI, Subsection IWE Program (B.2.1.27)
- ASME Code Section XI, Subsection IWL Program (B.2.1.28)
- ASME Code Section XI, Subsection IWF Program (B.2.1.29)
- Boral Monitoring Program (B.2.2.2)
- Boric Acid Corrosion Program (B.2.1.4)
- Fire Protection Program (B.2.1.15)
- Inspection of Heavy Load and Light Load (Related to Refueling) Handling Systems Program (B.2.1.13)
- Structures Monitoring Program (B.2.1.31)
- Water Chemistry Program (B.2.1.2)

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:

- 10 CFR Part 50, Appendix J Program (B.2.1.30)
- TLAA Program (4.6)

LRA Tables 3.5.2-1 through 3.5.2-8 summarize AMRs for the structures and component supports component groups and indicate AMRs claimed to be 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 it does not recommend further evaluation, the staff's audit and review determined if the plant-specific components of these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant noted, for each AMR item, how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A–E, indicating how the AMR is consistent with the GALL Report.

Note A indicates that the AMR 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 items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR 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 items to verify consistency with the GALL Report and confirmed 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 item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, 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, in the GALL Report, a different component with the same material, environment, aging effect, and AMP as the component under review. The staff reviewed these items to verify consistency with the GALL Report. The staff also determined whether the AMR 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 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 items to verify consistency with the GALL Report. The staff confirmed whether the AMR item of the different component was applicable to the component under review and 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 item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff reviewed these 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's evaluation follows.

3.5.2.1.1 Aging Management Review Results Identified as Not Applicable

In Table 3.5.1, for items 3.5.1-5, 3.5.1-7, 3.5.1-8, 3.5.1-11, 3.5.1-13, 3.5.1-19, 3.5.1-20, 3.5.1-21, and 3.5.1-22, the applicant states that the corresponding AMR items in the GALL Report are not applicable because Seabrook is a PWR design that incorporates a reinforced concrete containment structure that is enclosed by a reinforced concrete containment enclosure structure. The AMR items in the GALL Report are only applicable to particular components of BWR designs that use a steel containment or containment systems that use a post-tensioning system. The staff confirmed that the stated AMR items in the GALL Report are only applicable to BWR designs or post-tensioned concrete containments and are not applicable to the Seabrook LRA.

LRA Table 3.5.1, item 3.5.1-49, is associated with SRP-LR Table 3.5-1, ID 49, which addresses steel and stainless steel support members exposed to treated water. The GALL Report recommends the Water Chemistry and ASME Code Section XI, Subsection IWF Programs to manage loss of material. The applicant stated that this item applies only to BWR designs; however, the staff noted that two items in LRA Table 3.5.2-6 reference item 3.5.1-49 for ASME Code Class 2 and Class 3 stainless steel supports in raw water. One of these items includes plant-specific note 514, which says that aging will be managed through the Structures Monitoring Program. It is unclear to the staff how aging of these components will be managed during the period of extended operation. Therefore, by letter dated January 5, 2011, the staff issued RAI 3.5.2.3.6-1 requesting that the applicant explain how aging of ASME Code Class 2 and Class 3 stainless steel supports will be managed.

By letter dated February 3, 2011, the applicant stated that the items were inadvertently addressed as "ASME Class 2/3 stainless steel supports" and should have been "Miscellaneous Mechanical Equipment stainless steel supports." Accordingly, the applicant revised the associated LRA items to reference LRA Table 3.2.1, item 3.2.1-37, the Structures Monitoring Program, and generic note E.

The staff reviewed the applicant's response and noted that based on the LRA revisions, the "BWR Only" comment associated with LRA item 3.5.1-49 is now accurate. The staff finds the applicant's not applicable identification acceptable.

The staff also reviewed the applicant's response to determine the acceptability of the updated reference to LRA Table 3.2.1, item 3.2.1-37, and associated Note E, as well as the use of the Structures Monitoring Program. The staff noted that for those items associated with item 3.2.1-37, the GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," which recommends periodic visual inspections to manage loss of material. The staff noted that the applicant's Structures Monitoring Program includes periodic visual inspections. The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. The staff finds the applicant's RAI response and proposal to manage aging using the Structures Monitoring Program acceptable because monitoring for this aging effect is done through periodic visual inspections by individuals that conduct the inspections and review the results in accordance with ANSI/ASCE 11-90, "Guideline for Structural Condition Assessment of Existing Buildings." The staff confirmed that ASME Code Class 2 and Class 3 stainless steel supports are included in the scope of the Structures Monitoring Program.

LRA Table 3.5.1, item 3.5.1-51 addresses high-strength, low-alloy steel bolts exposed to indoor-uncontrolled air. The GALL Report recommends the Bolting Integrity Program to manage cracking due to SCC and loss of material due to general corrosion for this component group. The applicant stated that this item is not applicable because there are no high-strength bolts that are subject to this aging effect. The staff evaluated the applicant's claim and found that in the Bolting Integrity Program description, the applicant indicated that it did have high-strength bolts (greater than or equal to150 ksi) that are used in ASME Code Section XI component support applications. The staff noted that three parameters must exist for SCC to occur in high-strength bolting. These parameters include a corrosive environment, a susceptible material, and high-sustained tensile stresses. Elimination or reduction in any of these three factors will decrease the likelihood of SCC occurring. The applicant stated that high-strength steel bolts used in ASME Code Section XI component support applications use slotted holes and double nuts in lieu of prestressing and are not subject to high-sustained preload stress. Additionally, the applicant stated that lubricants containing molybdenum disulfide or unacceptable levels of contaminants are not approved for use on these bolts. Therefore, the applicant concluded that SCC is not considered an applicable aging mechanism requiring management. The applicant is using the ASME Code Section XI, Subsection IWF Program to manage aging of these components. The staff finds the applicant's use of the ASME Code Section XI, Subsection IWF Program acceptable because these bolts are not susceptible to SCC, and this program uses visual inspection that is capable of detecting loss of material.

LRA Table 3.5.1, items 3.5.1-52 and 3.5.1-56, address Lubrite® sliding surfaces exposed to an uncontrolled air environment. The GALL Report recommends the Structures Monitoring Program and ASME Code Section XI, Subsection IWF Program, respectively, to manage these components for loss of mechanical function. The applicant stated that these items are not applicable because there are no sliding support bearings of surfaces at Seabrook that are subject to this aging effect. However, the staff noted that items in LRA Tables 3.5.2-1, 3.5.2-5, and 3.5.2-6 reference item 3.5.1-52 or 3.5.1-56. Because of this apparent contradictory information, it is unclear to the staff how aging of these components will be managed during the period of extended operation. Therefore, by letter dated January 5, 2011, the staff issued RAI 3.5.2.3.6-2 requesting that the applicant explain if there are any sliding support surfaces in the scope of license renewal and, if so, how aging of the supports will be managed.

By letter dated February 3, 2011, the applicant explained that sliding support surfaces were inadvertently omitted from LRA Table 3.5.1. Therefore, the applicant revised the discussion column of items 3.5.1-52 and 3.5.1-56 to note that the items were consistent with NUREG-1801, and aging is managed by the Structures Monitoring Program or the IWF Program, as recommended by the GALL Report.

The staff reviewed the applicant's response and finds it acceptable because it aligns LRA Table 3.5.1 with the associated items in LRA Tables 3.5.2-1, 3.5.2-5, and 3.5.2-6. It also aligns the LRA with the recommendations in the GALL Report. The staff's concern described in RAI 3.5.2.3.6-2 is resolved.

For item 3.5.1-57, the applicant claimed that it was not applicable. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results that are applicable for this item.

The remaining items identified as not applicable in LRA Table 3.5.1 require further evaluation and are discussed in the corresponding subsections of SER Section 3.5.2.2.

3.5.2.1.2 Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-Thaw

LRA Table 3.5.1, item 3.5.1-35, addresses discharge transition structure and revetment concrete exposed to outdoor air that is being managed for loss of material (spalling, scaling) and cracking due to freeze-thaw. The LRA credits the Structures Monitoring Program to manage these aging effects. The GALL Report recommends GALL Report AMP XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," to ensure that these aging effects are adequately managed for accessible areas. Several associated AMR items cite generic note E and plant-specific note 511, which states that the RG 1.127 AMP is incorporated into the applicant's Structures Monitoring Program.

GALL Report AMP XI.S7 recommends monitoring and visual inspection at intervals not to exceed 5 years for indications of cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, erosion, cavitation, seepage, and leakage to manage the aging of these items. In its review of components associated with item 3.5.1-35, for which the applicant cited generic note E, the staff noted that the Structures Monitoring Program proposes to manage aging of concrete exposed to outdoor air-outdoor through the use of periodic visual inspections at an interval not to exceed 5 years.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. In its review of components associated with item 3.5.1-35, the staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because monitoring for aging effects is done through periodic visual inspections. The staff noted that deficiencies are identified in accordance with ACI 201.1R and that periodic inspections are conducted on a 5-year basis. The staff also noted that the applicant's Structures Monitoring Program incorporates the guidance of the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants Program," and is consistent with GALL Report AMP XI.S7, which is identified as the appropriate AMP in the GALL Report.

The staff concludes that the applicant 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).

3.5.2.1.3 Loss of Material Due to Abrasion, Cavitation and Loss of Material Due to General (steel only), Pitting and Crevice Corrosion

LRA Table 3.5.1, item 3.5.1-45, addresses concrete exposed to a raw water (external) environment being managed for loss of material due to abrasion and cavitation. The LRA credits the Structures Monitoring Program to manage this aging effect. The GALL Report recommends GALL Report AMP XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," to ensure that this aging effect is adequately managed. Several associated AMR items cite generic note E, and plant-specific note 511, which states that the RG 1.127 AMP is incorporated into the applicant's Structures Monitoring Program.

GALL Report AMP XI.S7 recommends monitoring and inspection at intervals not to exceed 5 years for indications of cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, erosion, cavitation, seepage, and leakage to manage the aging of these items. In its review of components associated with item 3.5.1-45, for which the applicant cited generic note E, the staff noted that the Structures Monitoring Program proposes to manage aging of concrete exposed to raw water (external) through the use of periodic visual inspections at an interval not to exceed 5 years.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. In its review of components associated with item 3.5.1-45, the staff finds the applicant's proposal to manage concrete aging using the Structures Monitoring Program acceptable because monitoring for aging effects is done through periodic visual inspections. The staff noted that deficiencies are identified in accordance with ACI 201.1R and that the periodic inspections are conducted on a 5-year basis. The staff also noted that the applicant's Structures Monitoring Program incorporates the guidance of the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants Program," and is consistent with GALL Report AMP XI.S7, which is identified as the appropriate AMP in the GALL Report.

The staff concludes that the applicant 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 3.5.1, item 3.5.1-47, addresses carbon steel exposed to air-outdoor or raw water and stainless steel exposed to an air-outdoor environment, being managed for loss of material due to general (steel only), pitting, and crevice corrosion. The LRA credits the Structures Monitoring Program to manage this aging effect. The GALL Report recommends GALL Report AMP XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," to ensure that this aging effect is adequately managed. Several associated AMR items cite generic note E and plant-specific note 511, which state that the RG 1.127 AMP is incorporated into the applicant's Structures Monitoring Program, often in tandem with plant-specific note 503 or plant-specific note 509. Plant-specific note 503 states that aging effects include crevice and pitting corrosion along with loss of material corrosion due to a saltwater atmosphere environment. Plant-specific note 509 states that the referenced item(s) are buried, below grade, soil, and groundwater, where raw and treated water environments are treated the same.

GALL Report AMP XI.S7 recommends monitoring and visual inspection at intervals not to exceed 5 years to determine structural integrity. In its review of components associated with item 3.5.1-47, for which the applicant cited generic note E, the staff noted that the Structures Monitoring Program proposes to manage aging of carbon steel exposed to air-outdoor or raw water and stainless steel exposed to an air-outdoor environment through the use of periodic visual inspections at an interval not to exceed 5 years.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. In its review of components associated with item 3.5.1-47, the staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because monitoring for aging effects is done through periodic visual inspections. The staff noted that the applicant's Structures Monitoring Program incorporates the guidance of RG 1.127, and is consistent with GALL Report AMP XI.S7, which is identified as the appropriate AMP in the GALL Report.

The staff concludes that the applicant 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).

3.5.2.1.4 Loss of Material and Loss of Form Due to Erosion, Settlement, Sedimentation, Frost Action, Waves, Currents, Surface Runoff, and Seepage

LRA Table 3.5.1, item 3.5.1-48, addresses a rock (riprap) revetment exposed to an air-outdoor environment that is being managed for loss of material and loss of form. The LRA credits the Structures Monitoring Program to manage these aging effects. The GALL Report recommends GALL Report AMP XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E and plant-specific note 511, which state that the RG 1.127 AMP is incorporated into the applicant's Structures Monitoring Program.

GALL Report AMP XI.S7 recommends monitoring and inspection at intervals not to exceed 5 years for indications of cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, erosion, cavitation, seepage, and leakage to manage the aging of these items. In its review of components associated with item 3.5.1-48, for which the applicant cited generic note E, the staff noted that the Structures Monitoring Program proposes to manage aging of the rock (riprap) revetment exposed to air-outdoor through the use of periodic visual inspections at an interval not to exceed 5 years.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. In its review of components associated with item 3.5.1-48, the staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because monitoring for aging effects is done through periodic visual inspections. The staff noted that the applicant's Structures Monitoring Program incorporates the guidance of RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants Program," and is consistent with GALL Report AMP XI.S7, which is identified as the appropriate AMP in the GALL Report.

The staff concludes that the applicant 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).

3.5.2.1.5 Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling) Due to Aggressive Chemical Attack

LRA Table 3.5.1, item 3.5.1-34, addresses concrete exposed to an air-indoor or air-outdoor environment that is being managed for cracking, loss of bond, and loss of material (spalling, scaling) due to aggressive chemical attack. The LRA credits the Structures Monitoring Program to manage these aging effects. The GALL Report recommends GALL Report AMP XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E and plant-specific note 511, which state that the RG 1.127 AMP is incorporated into the applicant's Structures Monitoring Program.

GALL Report AMP XI.S7 recommends monitoring and inspection at intervals not to exceed 5 years for indications of cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, erosion, cavitation, seepage, and leakage to manage the aging of these items. In its review of components associated with item 3.5.1-34, for which the applicant cited generic note E, the staff noted that the Structures Monitoring Program proposes to manage aging of concrete exposed to an air-indoor or air-outdoor environment through the use of periodic visual inspections at an interval not to exceed 5 years.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. In its review of components associated with item 3.5.1-34, the staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because monitoring for aging effects is done through periodic visual inspections. The staff noted that the deficiencies are identified in accordance with ACI 201.1R. The staff also noted that the applicant's Structures Monitoring Program incorporates the guidance of RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants Program," and is consistent with GALL Report AMP XI.S7, which is identified as the appropriate AMP in the GALL Report.

The staff concludes that the applicant 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).

3.5.2.1.6 Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling) Due to Aggressive Chemical Attack, and Loss of Strength Due to Leaching of Calcium Hydroxide

LRA Table 3.5.1, item 3.5.1-24, addresses concrete exposed to an air-indoor or air-outdoor environment that is being managed for increase in porosity and permeability, cracking, and loss of material (scaling, spalling) due to aggressive chemical attack. For two items, the LRA credits the Fire Protection Program to manage these aging effects. The GALL Report recommends GALL Report AMP XI.S6, "Structural Monitoring Program," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E.

GALL Report AMP XI.S6 selects parameters to be monitored or inspected for each structure and aging effect combination to ensure that aging degradation leading to loss of intended function will be detected and the extent of degradation detected. Inspection methods, inspection schedule, and inspector qualifications are to be commensurate with industry codes, standards, and guidelines. For concrete structures, this usually consists of visual inspections on a 5- or 10-year interval. In its review of components associated with item 3.5.1-24, for which the applicant cited generic note E, the staff noted that the Fire Protection Program proposes to manage increase in porosity and permeability, cracking, and loss of material (scaling, spalling) of concrete exposed to an air environment through the use of periodic visual inspections.

The staff's evaluation of the Fire Protection Program is documented in SER Section 3.0.3.2.7. In its review of components associated with item 3.5.1-24, the staff finds the applicant's proposal to manage aging acceptable because exposed surfaces are inspected at 18-month intervals for indications of increase in porosity and permeability, cracking, and loss of material (spalling, scaling). The staff noted that the inspection results are acceptable if there are no visual indications of cracking, spalling, and loss of material. In addition, the staff noted that the components are also being inspected by the Structures Monitoring Program, which is the GALL Report recommended program.

The staff concludes that the applicant 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 3.5.1, item 3.5.1-34, addresses below-grade concrete exposed to soil that is being managed for increase in porosity and permeability, cracking, and loss of material (scaling, spalling) due to aggressive chemical attack. The LRA credits the Structures Monitoring Program to manage these aging effects. The GALL Report recommends GALL Report AMP XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E and plant-specific note 511, which states that the RG 1.127 AMP is incorporated into the applicant's Structures Monitoring Program.

GALL Report AMP XI.S7 recommends monitoring and inspection at intervals not to exceed 5 years for indications of cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, erosion, cavitation, seepage, and leakage to manage the aging of these items. In its review of components associated with item 3.5.1-34, for which the applicant cited generic note E, the staff noted that the Structures Monitoring Program proposes to manage aging of below-grade concrete exposed to soil through the use of periodic visual inspections and monitoring of the aggressiveness of the groundwater.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. In its review of components associated with item 3.5.1-34, the staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because monitoring for aging effects is done through periodic inspections. The staff also noted that examinations of inaccessible areas will be completed during inspections of opportunity or, if no opportunistic inspections are performed during a 5-year period, a focused inspection is required. Additionally, groundwater is tested at 5-year intervals, and testing of concrete to determine the effects of aggressive groundwater is scheduled during the second and third quarter of 2010. The staff further noted that the applicant's Structures Monitoring Program incorporates the guidance of the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants Program," and is consistent with GALL Report AMP XI.S7, which is identified as the appropriate AMP in the GALL Report.

The staff concludes that the applicant 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 3.5.1, item 3.5.1-37, addresses concrete exposed to a raw water or soil environment being managed for increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide. The LRA credits the Structures Monitoring Program to manage these aging effects. The GALL Report recommends GALL Report AMP XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E and plant-specific note 511, which states that the RG 1.127 AMP is incorporated into the applicant's Structures Monitoring Program. Below grade concrete revetment items under this LRA table number also list generic note 509, which states that buried, below grade, soil, and groundwater, raw and treated water environments for these items are considered the same.

GALL Report AMP XI.S7 recommends monitoring and inspection at intervals not to exceed 5 years for indications of cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, erosion, cavitation, seepage, and leakage to manage the aging of these items. In its review of components associated with item 3.5.1-37, for which the applicant cited generic note E, the staff noted that the Structures Monitoring Program proposes to manage aging of concrete exposed to raw water or soil through the use of periodic visual inspections.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. Pending the resolution of OI 3.0.3.2.18-1, the staff can not complete its evaluation of this AMR item.

The staff finds that for LRA Item 3.5.1-37, OI 3.0.3.2.18-1 must be resolved before the staff can conclude 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.

3.5.2.1.7 Cracking Due to Expansion and Reaction with Aggregates[3]

LRA Table 3.5.1, item 3.5.1-36, addresses concrete exposed to air-indoor or air-outdoor, raw water, or soil environments being managed for expansion and cracking. The LRA credits the Structures Monitoring Program to manage these aging effects. The GALL Report recommends GALL Report AMP XI.S7, “Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants,” to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E and plant-specific note 511, which states that the RG 1.127 AMP is incorporated into the applicant’s Structures Monitoring Program.

GALL Report AMP XI.S7 recommends monitoring and inspection at intervals not to exceed 5 years for indications of cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, erosion, cavitation, seepage, and leakage to manage the aging of these items. In its review of components associated with item 3.5.1-36, for which the applicant cited generic note E, the staff noted that the Structures Monitoring Program proposes to manage aging of concrete exposed to air-indoor or air-outdoor, raw water, or soil environments through the use of periodic visual inspections at an interval not to exceed 5 years.

The staff’s evaluation of the applicant’s Structures Monitoring Program is documented in SER Section 3.0.3.2.18. Pending the resolution of OI 3.0.3.2.18-1, the staff can not complete its evaluation of this AMR item.

The staff finds that for LRA Item 3.5.1-36, OI 3.0.3.2.18-1 must be resolved before the staff can conclude 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.

3.5.2.1.8 Cracking Due to Restraint Shrinkage, Creep, and Aggressive Environment

LRA Table 3.5.1, item 3.5.1-43, addresses concrete masonry block walls exposed to air-indoor uncontrolled and air-outdoor environments that are being managed for cracking. Several items in the LRA credit the Fire Protection Program to manage this aging effect. The GALL Report recommends GALL Report AMP XI.S5, “Masonry Wall Program,” to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E supplemented for fire pump house fire barriers and SBO structures supports with plant-specific note 513, which identifies the Fire Protection Program to manage the aging effects for cracking. The non-essential switch gear building supports are supplemented with plant-specific note 511, which states that the XI.S7, “RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants,” and the XI.S5, “Masonry Wall Program,” guidance are incorporated into the applicant’s Structures Monitoring Program.

GALL Report AMP XI.S5 performs visual examination of the masonry walls by qualified inspection personnel for cracking of the masonry and degradation of steel edge supports and bracing at a frequency to ensure that there is no loss of intended function between inspections. In its review of components associated with item 3.5.1-43, for which the applicant cited generic note E, the staff noted the Fire Protection Program proposes to manage aging of concrete masonry unit structures through the use of periodic visual inspections.

[3] The applicant submitted a supplement to the LRA dated May 16, 2012, which addresses a plant-specific aging management program entitled "Alkali-Silica Reaction Monitoring Program." The staff is currently reviewing this supplement, and therefore, its evaluation is not included in this SER with open items.

The staff's evaluation of the applicant's Fire Protection Program is documented in SER Section 3.0.3.2.7. In its review of components associated with item 3.5.1-43, the staff finds the applicant's proposal to manage aging using the Fire Protection Program acceptable because monitoring of exposed surfaces is done through inspections at 18-month intervals for indications of increase in porosity and permeability, cracking, loss of material (spalling, scaling), and loss of strength. The staff noted that inspection results are acceptable if there are no visual indications of cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and aggregate reactions. In addition, the staff noted that the additional non-essential switch gear building supports are also being inspected by the Structures Monitoring Program, which incorporates the recommendations of the GALL recommended program, AMP XI.S5, "Masonry Wall Program."

The staff concludes that the applicant 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).

3.5.2.2 Aging Management Review Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.5.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the containments, structures, and component supports and provides information concerning how it will manage aging effects in the following areas:

- 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
- 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 Group 7 and 8 stainless steel tank liners
    - aging of supports not covered by the Structures Monitoring Program
    - cumulative fatigue damage due to cyclic loading
- 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 if 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, as described below.

<u>Aging of Inaccessible Concrete Areas</u>. LRA Section 3.5.2.2.1.1 associated with LRA Table 3.5.1, item 3.5.1-1, addresses aging of inaccessible concrete areas, which are being managed for aggressive chemical attack and corrosion of embedded steel by the ASME Code Section XI, Subsection IWL Program. The criteria in SRP-LR Section 3.5.2.2.1.1 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 Code 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 applicant addressed the further evaluation criteria of the SRP-LR by stating that the groundwater at Seabrook is aggressive in that chloride levels between 19–3,900 ppm were obtained during testing from November 2008 to September 2009. The LRA states that, under the Structures Monitoring Program, examinations of inaccessible areas will be completed during inspections of opportunity or, if no opportunistic inspections are performed during a 5-year period, a focused inspection is required. Additionally, groundwater will be tested at 5-year intervals, and testing of concrete and inspections of rebar are scheduled to determine the effects of aggressive groundwater.

The staff's evaluation of the applicant's ASME Code Section XI, Subsection IWL Program is documented in SER Section 3.0.3.2.17. The staff noted that aging management of all accessible areas of the concrete containment building for cracking, loss of material, and increase in porosity and permeability is managed by the ASME Code Section XI, Subsection IWL Program. The staff also notes that since the below-grade environment is aggressive, the applicant will continue to monitor it for aggressiveness during the period of extended operation, as well as conduct focused or opportunistic inspections of inaccessible foundations during a 5-year interval, and concrete testing and rebar inspections will be performed to indicate the condition of below-grade concrete. In addition, the staff issued RAIs B.2.1.28-3 and B.2.1.31-1 under the IWL and Structures Monitoring Programs (SER Sections 3.0.3.2.17 and 3.0.3.2.18, respectively) requesting information on how the applicant will continue to verify the adequacy of concrete exposed to aggressive groundwater during the period of extended operation. This issue, including the applicant's response to the RAIs and the staff's review, is discussed in detail in those sections.

The staff is concerned that the inaccessible areas of the concrete containment may be exposed to the ASR since recent plant specific operating experience indicate presence of ASR in accessible portions of other concrete structures located close to the containment. Presence of ASR in the inaccessible portion of the concrete containment may result in an increase in rate of degradation of concrete due to porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack. The Structures Monitoring Program has to be enhanced to account for this phenomenon. This is being tracked as Open Item OI 3.0.3.2.18-1.

Based on the information provided to date, and until OI 3.0.3.2.18-1 is resolved, the staff can not complete its evaluation of components associated with item 3.5.1-1.

<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, associated with LRA Table 3.5.1, items 3.5.1-2 and 3.5.1-3, addresses concrete components being managed for 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 by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.1.2 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 applicant addressed the further evaluation criteria of the SRP-LR by stating that Seabrook structures are founded on sound bedrock, fill concrete, or consolidated backfill; there are no porous concrete subfoundations; the foundations are not subject to flowing water; and a dewatering system is not relied upon for control of settlement.

In its review of components associated with items 3.5.1-2 and 3.5.1-3, the staff noted that the applicant did not state that the Structures Monitoring Program will continue to inspect for possible signs of settlement. In addition, although a dewatering system is not used to control settlement, a dewatering system has been installed in an attempt to control groundwater leakage. Therefore, by letter dated January 5, 2011, the staff issued RAI 3.5.2.2.1.2-1 requesting that the applicant justify not including degradation due to settlement within the scope of the Structures Monitoring Program and explain whether or not the dewatering program has had any effect on settlement.

In its response dated February 3, 2011, the applicant stated that, historically, no indications of building settlements, such as cracking or warping of structural elements, have been identified with the exception of an isolated incident in the fuel storage building where deck plate seating alignment has been an issue. The applicant is actively monitoring this through laser targets to establish a baseline. Moreover, the applicant stated that the Structures Monitoring Program will continue to inspect for signs of settlement during the period of extended operation.

The staff finds the applicant's response acceptable because the applicant has no experience with settlement, and it monitors unusual occurrences. Additionally, the Structures Monitoring Program will continue to inspect for signs of settlement during the period of extended operation. The staff's concern described in RAI 3.5.2.2.1.2-1 is resolved.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. The staff noted that structures and structural components are monitored under the applicant's Structures Monitoring Program for aging effects related to settlement. The staff also noted that the applicant does not have porous concrete subfoundations or a dewatering system to control settlement, and all of its Seismic Category I structures are founded on solid, non-compressible material. In its review of components associated with items 3.5.1-2 and 3.5.1-3, the staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because this is the GALL Report recommended program, and all necessary components are within the program's scope.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.1.2 criteria. For those items that apply to LRA Section 3.5.2.2.1.2, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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).

<u>Reduction of Strength and Modulus of Concrete Structures due to Elevated Temperature</u>. LRA Section 3.5.2.2.1.3, associated with LRA Table 3.5.1, item 3.5.1-4, addresses reduction of strength and modulus of concrete structures exposed to elevated temperatures. The applicant stated that this item is not applicable because concrete is not exposed to temperatures above the limits. The applicant also stated that the containment structure cooling subsystem is designed to maintain the normal ambient air temperature in the containment structure at or below 120 ˚F and functions to prevent the concrete temperature in the area of the reactor supports from exceeding 135 ˚F during normal operation. The applicant further stated that if a pipe carries a hot fluid, the space between the pipe and sleeve is insulated to maintain the concrete temperature adjoining the sleeve at or below 200 ˚F during normal plant operation. The GALL Report recommends further evaluation for any concrete elements that exceed the specified temperature limits of 150 ˚F general and 200 ˚F local. The staff reviewed LRA Sections 2.3.3.4 and 3.5, and reviewed the UFSAR, and confirmed that the containment cooling system is within the scope of license renewal and that no in-scope containment concrete is exposed to temperatures exceeding the GALL Report limits; therefore, it finds the applicant's determination acceptable.

<u>Loss of Material due to General, Pitting and Crevice Corrosion</u>. LRA Section 3.5.2.2.1.4, associated with LRA Table 3.5.1, items 3.5.1-5 (not applicable; applies only to BWRs) and 3.5.1-6, addresses steel elements of accessible and inaccessible areas of containments, which are being managed for loss of material due to general, pitting, and crevice corrosion by the ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Programs. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the ASME Code 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 containment structure steel elements due to general, pitting, and crevice corrosion. The applicant also stated that the seismic isolation material between the fill mat and the containment liner is sealed at the mat surface with caulk, and the caulked joint is examined for signs of degradation under the ASME Code Section XI, Subsection IWL Program inspections. The applicant further stated that the ASME

Code Section XI, Subsection IWL Program is used to manage concrete aging effects. LRA Section 3.5 states that the concrete structures were designed in accordance with ACI 318 and constructed in accordance with ACI 301, ASTM standards, and recommendations equivalent to ACI 201.2R.

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 Code Section XI Subsection IWE, and 10 CFR Part 50, Appendix J Programs 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.A1-11 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.

During its review, the staff noted that although the applicant adequately addressed three of the four conditions discussed in the GALL Report, the LRA did not discuss the fourth condition. By letter dated January 5, 2011, the staff issued RAI 3.5.2.2.1.4-1 requesting that the applicant discuss Seabrook experience with water ponding on the containment floor.

In its response dated February 3, 2011, the applicant stated that the plant has no operating experience related to water ponding on the containment floor. The applicant explained that the design of the containment incorporates floors sloped towards the trench and sump system to prevent water ponding.

The staff reviewed the applicant’s response and finds it acceptable because the applicant explained that there is no plant-specific operating experience regarding water ponding on the containment floor. The staff’s concern described in RAI 3.5.2.2.1.4-1 is resolved.

The staff’s reviews of the applicant’s ASME Code Section XI, Subsection IWL Program, ASME Code Section XI, Subsection IWE Program, and 10 CFR Part 50, Appendix J Program are documented in SER Sections 3.0.3.2.17, 3.0.3.1.9, and 3.0.3.1.11, respectively. The staff noted that the concrete structures were designed in accordance with ACI 318 and constructed in accordance with ACI 301, ASTM standards, and recommendations equivalent to ACI 201.2R. The concrete and the moisture barrier where the liner becomes embedded are monitored under the ASME Code Section XI, Subsection IWL Program. The staff also confirmed that the containment internal concrete structures are within the scope of the Structures Monitoring Program and are visually inspected for penetrating cracks under that program. In addition, the staff reviewed the UFSAR and confirmed that the applicant has measures in place to alleviate accumulation of water in the containment. The staff finds that the applicant met the further evaluation criteria, and the applicant's proposal to manage aging is acceptable because the applicant satisfied the four conditions listed above, and the applicant is using the GALL Report recommended inspection programs.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.1.4 criteria. For those items that apply to LRA Section 3.5.2.2.1.4, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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).

Loss of Prestress due to Relaxation, Shrinkage, Creep, and Elevated Temperature. LRA Section 3.5.2.2.1.5, associated with LRA Table 3.5.1, item 3.5.1-7, addresses loss of prestress due to relaxation, shrinkage, creep, and elevated temperature in prestressed containment tendons. In the LRA, the applicant stated that this item is not applicable because the containment structure does not use a prestressed concrete containment design so there are no prestressing tendons. The staff finds the applicant's determination acceptable on the basis that the containment is a reinforced concrete containment with no prestressing tendons.

Cumulative Fatigue Damage. LRA Section 3.5.2.2.1.6 associated with LRA Table 3.5.1, items 3.5.1-8 (not applicable; applies only to BWRs) and 3.5.1-9, states that TLAAs are evaluated in accordance with 10 CFR54.21(c) and that the evaluation of this TLAA is addressed in Section 4.6.2. This is consistent with SRP-LR Section 3.5.2.2.1.6 and is, therefore, acceptable.

Cracking due to Stress Corrosion Cracking. LRA Section 3.5.2.2.1.7, associated with LRA Table 3.5.1, items 3.5.1-10 and 3.5.1-11 (not applicable; applies only to BWRs), addresses cracking due to SCC in stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds exposed to an air environment. The GALL Report recommends ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Programs, as well as additional examinations as appropriate to manage SCC for this component group. In the LRA, the applicant stated that these items are not applicable because no in-scope stainless steel penetration sleeves, penetration bellows, or dissimilar metal welds are subject to SCC. The staff evaluated the applicant's claim and found it acceptable because the Seabrook penetration sleeves, bellows, and dissimilar metal welds are not subject to a combination of high temperature (greater than 140 ˚F) and exposure to an aggressive environment, and plant-specific operating experience did not identify any SCC in these components.

Cracking Due to Cyclic Loading. LRA Section 3.5.2.2.1.8, associated with LRA Table 3.5.1, items 3.5.1-12 and 3.5.1-13, addresses cracking due to cyclic loading in penetration sleeves and bellows exposed to an air environment. In the LRA, the applicant stated that item 3.5.1-12 is not an aging effect requiring management, and analyses of the containment penetrations are not considered TLAAs. The applicant also stated that these components were designed to withstand operating stress levels and, as such, cracking due to cyclic loading is unlikely to occur, the plant will continue to operate within the design envelope in the period of extended operation, and plant operating experience has not identified any events related to cyclic loading-induced cracking of containment components. The applicant further stated that item 3.5.1-13 is not applicable because it applies only to BWR plants. The staff confirmed that fatigue of containment penetrations is not applicable because it applies only to BWR plants.

The lack of a TLAA is addressed in LRA Section 4.6.2, and the staff's review is documented in the corresponding SER section.

Loss of Material (Scaling, Cracking, and Spalling) due to Freeze-Thaw. LRA Section 3.5.2.2.1.9, associated with LRA Table 3.5.1, item 3.5.1-14, addresses loss of material (scaling, cracking, and spalling) in concrete elements due to freeze-thaw. The GALL Report recommends further evaluation of inaccessible areas for plants located in moderate to severe weathering conditions. In the LRA, the applicant stated that this item is not applicable because the Seabrook containment is enclosed by a concrete containment enclosure building and, therefore, is not exposed to severe weathering conditions. The staff confirmed that the containment is located in a concrete containment enclosure building and, therefore, is not subject to this AERM. Management of the enclosure building and other exterior concrete in the scope of license renewal is discussed in SER Section 3.5.2.2.2.

Cracking due to Expansion, and Reaction with Aggregate, and Increase in Porosity and Permeability due to Leaching of Calcium Hydroxide[4]. LRA Section 3.5.2.2.1.10, associated with LRA Table 3.5.1, item 3.5.1-15, addresses cracking due to expansion and reaction with aggregate and increase in porosity and permeability due to leaching of calcium hydroxide of concrete elements exposed to any environment, which are being managed for aging by the ASME Code Section XI, Subsection IWL Program. The criteria in SRP-LR Section 3.5.2.2.1.10 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. For accessible areas, the GALL Report recommends managing aging using the ASME Code Section XI, Subsection IWL AMP. For inaccessible areas, the GALL Report recommends further evaluation if the concrete was not constructed in accordance with the recommendations of ACI 201.2R. The applicant stated that the concrete structures were designed in accordance with ACI 318, constructed in accordance with ACI 301 and ASTM Standards, and met recommendations equivalent to those in ACI 201.2R. Aggregates identified as potentially reactive by petrographic examination in accordance with ASTM C295 were not used. The applicant further stated that there are indications of leaching of calcium hydroxide in below-grade structures other than the containment building and that the ASME Code Section XI, Subsection IWL and Structures Monitoring Program will be used to manage these aging effects.

The staff's reviews of the applicant's ASME Code Section XI, Subsection IWL and Structures Monitoring Programs are documented in SER Sections 3.0.3.2.17 and 3.0.3.2.18, respectively. In its review of components associated with item 3.5.1-15, the staff noted that the applicant used the appropriate ASTM standards to test for aggregate reactivity; however, recent plant-specific operating experience has indicated that alkali-aggregate reactions are occurring onsite. To address this operating experience, the staff issued RAIs B.2.1.28-3 and B.2.1.31-1 under the IWL and Structures Monitoring Programs, respectively, requesting information on how the applicant will manage aging effects due to aggregate reactions. This issue, including the applicant's response to RAIs and the staff's review, is documented in detail in SER Sections 3.0.3.2.17 and 3.0.3.2.18, and Open Item OI 3.0.3.2.18-1..

Based on the information provided to date, and until OI 3.0.3.2.18-1 is resolved, the staff can not complete its evaluation of components associated with item 3.5.1-15.

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[4] The applicant submitted a supplement to the LRA dated May 16, 2012, which addresses a plant-specific aging management program entitled "Alkali-Silica Reaction Monitoring Program." The staff is currently reviewing this supplement, and therefore, its evaluation is not included in this SER with open items.

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.

Aging of Structures Not Covered by Structures Monitoring Program. LRA Section 3.5.2.2.2.1 addresses aging of structures not covered by the Structures Monitoring Program.

(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, associated with LRA Table 3.5.1, item 3.5.1-23, addresses cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for concrete elements of Groups 1–5, 7, and 9 structures. The GALL Report recommends further evaluation of this structure and aging effect combination only if it is not covered by the Structures Monitoring Program. In the LRA, the applicant stated that this item is covered by the Structures Monitoring Program and does not require further evaluation.

The staff is concerned that the recent plant specific operating experience that indicate presence of ASR in the below-grade concrete structures may affect the scope and rate of degradation due to cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel. The Structures Monitoring Program has to be enhanced to account for this phenomenon. This is being tracked as Open Item OI 3.0.3.2.18-1.

Based on the information provided to date, and until OI 3.0.3.2.18-1 is resolved, the staff can not complete its evaluation of components associated with item 3.5.1-23.

(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, associated with LRA Table 3.5.1, item 3.5.1-24, addresses increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack for concrete elements of Groups 1–5, 7, and 9 structures. The GALL Report recommends further evaluation of this structure and aging effect combination only if it is not covered by the Structures Monitoring Program. In the LRA, the applicant stated that this item is covered by the Structures Monitoring Program and does not require further evaluation.

The staff is concerned that the recent plant operating experience indicating the presence of ASR in the below-grade concrete structures may affect the scope and rate of degradation due to increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack. The Structures Monitoring Program has to be enhanced to account for this phenomenon. This is being tracked as Open Item OI 3.0.3.2.18-1.

Based on the information provided to date, and until OI 3.0.3.2.18-1 is resolved, the staff can not complete its evaluation of components associated with item 3.5.1-24.

(3) Loss of Material due to Corrosion for Groups 1–5, 7, and 8 Structures

LRA Section 3.5.2.2.2.1, associated with LRA Table 3.5.1, item 3.5.1-25, addresses loss of material due to corrosion for Groups 1–5, 7, and 8 structures. The GALL Report recommends further evaluation of this structure and aging effect combination only if it is not covered by the Structures Monitoring Program. In the LRA, the applicant stated that this item is covered by the Structures Monitoring Program and does not require further evaluation.

The staff is concerned that the recent plant operating experience indicating the presence of ASR in the below-grade concrete structures may affect the scope and rate of degradation due to loss of material due to corrosion. The Structures Monitoring Program has to be enhanced to account for this phenomenon. This is being tracked as Open Item OI 3.0.3.2.18-1.

Based on the information provided to date, and until OI 3.0.3.2.18-1 is resolved, the staff can not complete its evaluation of components associated with item 3.5.1-25.

(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, associated with LRA Table 3.5.1, item 3.5.1-26, addresses loss of material (scaling, cracking, and spalling) in concrete elements due to freeze-thaw. The GALL Report recommends further evaluation of this structure and aging effect combination only if it is not covered by the Structures Monitoring Program. In the LRA, the applicant stated that this item is covered by the Structures Monitoring Program and does not require further evaluation. The staff confirmed that the structure and aging effect combination is covered by the Structures Monitoring Program and, therefore, finds the applicant's determination acceptable. The staff's review of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18.

(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, associated with LRA Table 3.5.1, item 3.5.1-27, addresses cracking due to reaction with aggregates for Groups 1–5, and 7–9 structures. The GALL Report recommends further evaluation of this structure and aging effect combination only if it is not covered by the Structures Monitoring Program. In the LRA, the applicant stated that this item is covered by the Structures Monitoring Program.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. Pending the resolution of OI 3.0.3.2.18-1, the staff can not complete its evaluation of this AMR item.

The staff finds that for LRA Item 3.5.1-27, OI 3.0.3.2.18-1 must be resolved before the staff can conclude 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.

(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, associated with LRA Table 3.5.1, item 3.5.1-28, addresses cracks and distortion due to increased stress levels from settlement for Groups 1–3 and 5–9 structures. The GALL Report recommends further evaluation of this structure and aging effect combination only if it is not covered by the Structures Monitoring Program. The applicant stated in the LRA that this item does not require further evaluation because Seabrook structures are founded on sound bedrock, fill concrete, or engineered backfill, and a dewatering system is not relied upon for control of settlement. The staff reviewed the UFSAR and confirmed that Seabrook structures are founded on bedrock, fill concrete, or engineered backfill, and a dewatering system is not relied upon for control of settlement and, therefore, finds the applicant's determination acceptable.

(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, associated with LRA Table 3.5.1, item 3.5.1-29, addresses reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations for Groups 1–3 and 5–9 structures. The GALL Report recommends further evaluation of this structure and aging effect combination only if it is not covered by the Structures Monitoring Program. The applicant stated that this item is not applicable because porous concrete subfoundations were not used at Seabrook. The staff reviewed the UFSAR and confirmed that no porous concrete subfoundations are present at Seabrook and, therefore, finds the applicant's determination acceptable.

(8) Lockup due to Wear for Lubrite® Radial Beam Seats in BWR Drywell and Other Sliding Support Surfaces

LRA Section 3.5.2.2.2.1, associated with LRA Table 3.5.1, item 3.5.1-30, addresses lock-up due to wear in Lubrite® supports exposed to an air-indoor environment. The GALL Report recommends further evaluation of this structure and aging effect combination only if it is not covered by the Structures Monitoring Program or the IWF Program. In the LRA, the applicant stated that this item is covered by the Structures Monitoring and the ASME Code Section XI, Subsection IWF Programs. The staff confirmed that the structure and aging effect combination is covered by the Structures Monitoring and the ASME Code Section XI, Subsection IWF Programs and, therefore, finds the applicant's determination acceptable. Aging management of sliding supports is also discussed in SER Section 3.5.2.3.6, in the review of the applicant's response to RAI 3.5.2.3.6-2. The staff's reviews of the applicant's Structures Monitoring and ASME Code Section XI, Subsection IWF Programs are documented in SER Sections 3.0.3.2.18 and 3.0.3.1.10, respectively.

<u>Aging Management of Inaccessible Areas</u>. LRA Section 3.5.2.2.2.2 addresses aging management of inaccessible areas (Below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 Structures).

(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.

LRA Section 3.5.2.2.2.2.1, associated with LRA Table 3.5.1, item 3.5.1-26, addresses loss of material (scaling, cracking, and spalling) due to freeze-thaw of inaccessible concrete elements exposed to soil and outdoor air. The criteria in SRP-LR Section 3.5.2.2.2.2, item 1, recommends further evaluation for plants located in areas having moderate to severe weathering conditions. The SRP-LR also notes that existing concrete with an air content of 3–6 percent and a water-to-cement ratio between 0.35–0.45 did not exhibit degradation related to freeze-thaw. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the concrete structures were designed in accordance with ACI 318 and constructed in accordance with ACI 301, ASTM standards, and recommendations equivalent to ACI 201.2R. The air content of the concrete is higher than 6 percent but within the acceptable guidelines of ACI 201 and ACI 318. In addition, the LRA states that, under the Structures Monitoring Program, examinations of inaccessible areas will be completed during inspections of opportunity or, if no opportunistic inspections are performed during a 5-year period, a focused inspection is required. The LRA also states that the condition of accessible areas may be used to evaluate the condition of inaccessible areas.

The staff noted that the applicant's air content is above the 6 percent recommendation in the GALL Report. The staff also noted that the applicant will inspect for freeze-thaw degradation in accessible areas and use the results to evaluate the condition of inaccessible areas, and examinations of opportunity will be conducted on inaccessible areas. In addition, the staff noted that although the applicant's external structures are exposed to freeze-thaw cycles, a review of plant operating experience did not reveal concrete degradation attributed to freeze-thaw. The staff further noted that the GALL Report suggests existing concrete exposed to potential freeze-thaw have a water-to-cement ratio between 0.35–0.45. The staff noted that 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 January 5, 2011, the staff issued RAI 3.5.2.2.2.2-1 requesting that the applicant provide justification to address compliance of the Seabrook concrete to recommendations provided in the GALL Report.

In its response dated February 3, 2011, the applicant stated that the water-to-cement ratio varies from 0.45–0.53. The applicant further stated that although the ratio exceeds the recommendations of the GALL Report, it was selected on the basis of strength requirements per specification "Standard Concrete Mixes."

The staff finds the applicant's response acceptable because the applicant will manage this aging effect with the Structures Monitoring Program. Any indications of degradation in accessible areas will be used to evaluate inaccessible areas. In addition, a review of plant operating experience did not reveal concrete degradation attributed to freeze-thaw. The staff's concern described in RAI 3.5.2.2.2.2-1 is resolved.

The staff finds the applicant's further evaluation acceptable because the concrete air content limit was increased to 8 percent (including tolerance) in GALL Report, Rev. 2, Section 3.5.3.2.1.7. In addition, the Seabrook concrete air content is acceptable per ACI 201 and ACI 318 guidelines, and the staff did not identify any plant-specific operating experience related to freeze-thaw in either the accessible or inaccessible concrete surfaces. The applicant will continue to inspect the accessible concrete surfaces in accordance with the Structures Monitoring Program during the current licensing period as well as during the period of extended operation. Additionally, the applicant will conduct opportunistic inspections of inaccessible areas, and results of inspections of accessible areas will be used to evaluate the condition of inaccessible areas. The accessible concrete exposed to atmosphere is more susceptible to freeze-thaw because it is more likely to be subjected to alternate freeze-thaw cycles. The inaccessible concrete located below grade is not normally subjected to such freeze-thaw conditions.

Based on the evaluation provided, the staff concludes that the applicant met SRP-LR Section 3.5.2.2.2.2, item 1, criteria. For those items that apply to LRA Section 3.5.2.2.2.2.1, the staff determined that the LRA is consistent with the GALL Report, and the applicant 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) Cracking due to Expansion and Reaction with Aggregates Could Occur in Below-Grade Inaccessible Concrete Areas for Groups 1–5 and 7–9 Structures[5].

LRA Section 3.5.2.2.2.2.2, associated with LRA Table 3.5.1, item 3.5.1-27, addresses cracking due to reaction with aggregates for inaccessible areas of Groups 1–5 and 7–9 structures. The SRP-LR Section 3.5.2.2.2.2, item 2, states that further evaluation of this structure and aging effect combination for inaccessible areas is not necessary if examinations, performed in accordance with ASTM standards C227 or C295, demonstrate that the aggregates are non-reactive or the concrete was constructed in accordance with ACI 201.2R. In the LRA, the applicant stated that this item does not require further evaluation because tests and petrographic examinations, performed in accordance with ASTM C227-50 or ASTM C295-54, confirmed that the aggregate materials were not reactive, and the concrete was constructed using recommendations equivalent to ACI 201.2R. The applicant also stated that the aging effect would be managed in accessible areas by the Structures Monitoring Program.

The staff reviewed the UFSAR and confirmed that aggregates were tested for reactivity in accordance with ASTM C227 or C295, and the concrete was constructed in accordance with recommendations in ACI 201.2R; however, recent plant-specific operating experience has indicated that alkali-aggregate reactions are occurring onsite. To address this operating experience, the staff issued RAIs B.2.1.28-3 and B.2.1.31-1 under the IWL and Structures Monitoring Programs, respectively, requesting information on how the applicant will manage aging effects due to aggregate reactions. This issue, including the applicant's response to the RAIs and the staff's review, is discussed in detail in SER sections 3.0.3.2.17 and 3.0.3.2.18, and Open Item OI 3.0.3.2.18-1.

Based on the information provided to date, and until OI 3.0.3.2.18-1 is resolved, the staff can not complete its evaluation of components associated with item 3.5.1-27.

(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.

LRA Section 3.5.2.2.2.2.3, associated with LRA Table 3.5.1, items 3.5.1-28 and 3.5.1-29, addresses cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion

[5] The applicant submitted a supplement to the LRA dated May 16, 2012, which addresses a plant-specific aging management program entitled "Alkali-Silica Reaction Monitoring Program." The staff is currently reviewing this supplement, and therefore, its evaluation is not included in this SER with open items.

of porous concrete subfoundations for inaccessible areas of Groups 1–3 and 5–9 structures. The SRP-LR Section 3.5.2.2.2.2, item 3, recommends no further evaluation if this activity is included in the scope of the applicant's Structures Monitoring Program.

These aging effects are included in the scope of the applicant’s Structures Monitoring Program, and no dewatering system is used. In the LRA, the applicant stated that these items do not require further evaluation because Seabrook structures are founded on sound bedrock, fill concrete, or consolidated backfill; there are no porous concrete subfoundations and the foundations are not subject to flowing water; and a dewatering system is not relied upon for control of settlement. The staff reviewed the UFSAR and confirmed that the structures are founded on sound bedrock, fill concrete, or consolidated backfill; a dewatering system is not used; and there are no porous subfoundations on the site. In addition, the staff noted that the applicant’s Structures Monitoring Program inspects for cracking, regardless of aging mechanism. Therefore, the staff finds acceptable the applicant’s determination that further evaluation is not required. The staff’s review of the applicant’s Structures Monitoring Program is documented in SER Section 3.0.3.2.18.

(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 associated with LRA Table 3.5.1, item 3.5.1-31, addresses below-grade concrete components exposed to a groundwater or soil environment, which are being managed for cracking, loss of material, and loss of bond due to aggressive chemical attack and corrosion of embedded steel. The criteria in SRP-LR Section 3.5.2.2.2.2, item 4, state that the GALL Report recommends further evaluation of plant-specific programs to manage these aging effects in inaccessible areas 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), the following, as a minimum, should be considered:

- examinations of the exposed portions of the below-grade concrete when excavated for any reason
- periodic monitoring of below-grade water chemistry, including consideration of potential seasonal variations

The applicant stated that the concrete structures were designed in accordance with ACI 318 and constructed in accordance with ACI 301 and ASTM standards, and the concrete complied with recommendations equivalent to those in ACI 201.2R. The applicant further stated that there are indications of leaching of calcium hydroxide in below-grade concrete structures. The groundwater at Seabrook is aggressive in that chloride levels between 19–3,900 ppm were obtained during testing from November 2008–September 2009, and plant operating experience notes that groundwater infiltration through cracks, capillaries, pore spaces, seismic isolation joints, and construction joints in concrete walls and floor slabs or below-grade concrete structures has occurred. The LRA also states that concrete testing and rebar inspection will be conducted to determine the effects of aggressive groundwater on the concrete. The testing will represent all below-grade concrete. The LRA also states that these aging effects and mechanisms are covered by the Structures Monitoring Program and that, under the Structures Monitoring Program, examinations of inaccessible areas will be completed during inspections of opportunity.

The staff noted that the applicant will inspect exposed portions of below-grade concrete when exposed for any reason and will monitor the groundwater for aggressiveness as defined in the GALL Report. The staff also noted that this aging effect will be managed in accessible areas through visual inspections under the Structures Monitoring Program. In addition, the applicant has plans in place to determine the effects of aggressive groundwater through concrete testing and rebar inspection. The adequacy of this testing program is addressed in the staff's evaluation of the applicant's Structures Monitoring Program, which is documented in SER Section 3.0.3.2.18.

The staff is concerned that the recent plant specific operating experience indicating presence of ASR in below-grade concrete structures may affect the scope and rate of degradation due to 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 due to corrosion of embedded steel. The Structures Monitoring Program has to be enhanced to account for this phenomenon. This is being tracked as Open Item OI 3.0.3.2.18-1.

Based on the information provided to date, and until OI 3.0.3.2.18-1 is resolved, the staff can not complete its evaluation of components associated with item 3.5.1-31.

(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 associated with LRA Table 3.5.1, item 3.5.1-32, addresses below-grade concrete components exposed to a flowing water or soil environment, which are being managed for increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide. The criteria in SRP-LR Section 3.5.2.2.2.2, item 5, states that further evaluation is not necessary if concrete was constructed in accordance with the recommendations in ACI 201.2R.

The staff is concerned that the recent plant specific operating experience indicating the presence of ASR in the below-grade concrete structures may affect the scope and rate of degradation due to 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 due to corrosion of embedded steel. The Structures Monitoring Program has to be enhanced to account for this phenomenon. This is being tracked as Open Item OI 3.0.3.2.18-1.

Based on the information provided to date, and until OI 3.0.3.2.18-1 is resolved, the staff can not complete its evaluation of components associated with item 3.5.1-32.

<u>Reduction of Strength and Modulus of Concrete Structures due to Elevated Temperature</u>. LRA Section 3.5.2.2.2.3, associated with LRA Table 3.5.1, item 3.5.1-33, addresses reduction of strength and modulus of concrete structures exposed to elevated temperatures. The GALL Report recommends further evaluation for any concrete elements that exceed the specified temperature limits of 150 ˚F general and 200 ˚F local. The applicant stated that this item is not applicable because no Group 1–5 concrete structures are exposed to temperatures above the

GALL Report limits. The staff reviewed the UFSAR and confirmed that no in-scope concrete is exposed to temperatures exceeding the GALL Report limits; therefore, it finds the applicant's determination acceptable.

Aging Management of Inaccessible Areas for Group 6 Structures. LRA Section 3.5.2.2.2.4 addresses aging management of inaccessible areas for Group 6 structures (below-grade inaccessible concrete areas).

(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.

LRA Section 3.5.2.2.2.4.1 associated with LRA Table 3.5.1, item 3.5.1-34, addresses below-grade concrete components exposed to a groundwater or soil environment, which are being managed for increase in porosity and permeability, cracking, loss of material, and loss of bond due to aggressive chemical attack and corrosion of embedded steel. The criteria in SRP-LR Section 3.5.2.2.2.4, item 1, state that the GALL Report recommends further evaluation of plant-specific programs to manage these aging effects in inaccessible areas 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), the following, as a minimum, should be considered:

- examinations of the exposed portions of the below-grade concrete when excavated for any reason
- periodic monitoring of below-grade water chemistry, including consideration of potential seasonal variations

The applicant stated that the concrete structures were designed in accordance with ACI 318 and constructed in accordance with ACI 301 and ASTM standards. The groundwater at Seabrook is aggressive in that chloride levels between 19–3,900 ppm were obtained during testing from November 2008–September 2009. The LRA states that, under the Structures Monitoring Program (B.2.1.31), examinations of inaccessible areas will be completed during inspections of opportunity or, if no opportunistic inspections are performed during a 5-year period, a focused inspection is required. Additionally, groundwater will be tested at 5-year intervals, and testing of concrete and inspections of rebar representative of the below-grade concrete are scheduled to determine the effects of aggressive groundwater.

The staff is concerned that the recent plant operating experience indicating the presence of ASR in the below-grade concrete structures may affect the scope and rate of degradation due to 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 due to corrosion of embedded steel. The Structures Monitoring Program has to be enhanced to account for this phenomenon. This is being tracked as Open Item OI 3.0.3.2.18-1.

Based on the information provided to date, and until OI 3.0.3.2.18-1 is resolved, the staff can not complete its evaluation of components associated with item 3.5.1-34.

(2) Loss of Material (Spalling, Scaling) and Cracking due to Freeze-Thaw that Could Occur in Below-Grade Inaccessible Concrete Areas of Group 6 Structures.

LRA Section 3.5.2.2.2.4.2, associated with LRA Table 3.5.1, item 3.5.1-35, addresses loss of material (scaling, cracking, and spalling) of inaccessible concrete elements due to freeze-thaw in Group 6 structures. The criteria in SRP-LR Section 3.5.2.2.2.4, item 2, states that the GALL Report recommends further evaluation for plants located in areas having moderate to severe weathering conditions if the concrete does not have an air content of 3–6 percent and a water-to-cement ratio between 0.35–0.45. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the concrete was a dense, durable mixture of sound coarse aggregate, cement, and water, and that it had an air content higher than 6 percent but within the acceptable guidelines of ACI 201 and ACI 318. The applicant further stated that the Structures Monitoring Program will manage loss of material due to freeze-thaw during the period of extended operation.

The staff's review of the adequacy of the applicant's aging management approach for these aging effects on inaccessible elements of reinforced concrete structures is documented in SER Section 3.5.2.2.2, "Aging Management of Inaccessible Areas, Item 1." That review addresses the applicant's aging management approach for all concrete structures within the scope of license renewal, including Group 6 structures.

(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[6].

LRA Section 3.5.2.2.2.4.3, associated with LRA Table 3.5.1, item 3.5.1-36, addresses cracking due to reaction with aggregates for Group 6 structures. The applicant stated that tests and petrographic examinations, performed in accordance with ASTM C227-50 or ASTM C295-54, confirmed that the aggregate materials are not reactive; however, the Structures Monitoring Program is used to manage this structure and aging effect.

The staff's review of the adequacy of the applicant's further evaluation for these aging effects on inaccessible elements of reinforced concrete structures is documented in SER Section 3.5.2.2.2, "Aging Management of Inaccessible Areas, Item 2." That review addresses the applicant's aging management approach for all concrete structures within the scope of license renewal, including Group 6 structures.

LRA Section 3.5.2.2.2.4.3 associated with LRA Table 3.5.1, item 3.5.1-37, addresses below-grade concrete components exposed to a flowing water or soil environment, which are being managed for increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide. The criteria in SRP-LR Section 3.5.2.2.2.4, item 3, states that further evaluation is not necessary if concrete was constructed in accordance with the recommendations in ACI 201.2R. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Structures Monitoring Program is used to manage this structure and aging effect.

The staff's review of the adequacy of the applicant's aging management approach for these aging effects on inaccessible elements of reinforced concrete structures is

[6] The applicant submitted a supplement to the LRA dated May 16, 2012, which addresses a plant-specific aging management program entitled "Alkali-Silica Reaction Monitoring Program." The staff is currently reviewing this supplement, and therefore, its evaluation is not included in this SER with open items.

documented in SER Section 3.5.2.2.2, “Aging Management of Inaccessible Areas, Item 5.” That review addresses the applicant’s aging management approach for all concrete structures within the scope of license renewal, including Group 6 structures.

Based on the information provided to date, and until OI 3.0.3.2.18-1 is resolved, the staff can not complete its evaluation of components associated with item 3.5.1-36 and 3.5.1-37.

Cracking Due to Stress Corrosion Cracking and Loss of Material due to Pitting and Crevice Corrosion. LRA Section 3.5.2.2.2.5, associated with LRA Table 3.5.1, item 3.5.1-38, addresses cracking due to SCC and loss of material due to pitting and crevice corrosion for Group 7 and 8 stainless steel tank liners. The applicant stated that SCC is not applicable because the tank liners are not subjected to a standing water environment or temperatures above 140 ˚F. The applicant further stated that loss of material is an applicable aging effect, which is managed by appropriate AMPs. The staff reviewed the LRA and the UFSAR and confirmed that the stainless steel tank liners are not subjected to a corrosive environment or temperatures above 140 ˚F, and tank liners are managed for loss of material; therefore, the staff finds acceptable the applicant’s determination that further evaluation is not required.

Aging of Supports Not Covered by the Structures Monitoring Program. LRA Section 3.5.2.2.2.6 addresses aging of supports not covered by the Structures Monitoring Program.

(1) Loss of Material due to General and Pitting Corrosion for Groups B2–B5 Supports

LRA Section 3.5.2.2.2.6, associated with LRA Table 3.5.1, item 3.5.1-39, addresses loss of material due to general and pitting corrosion of Groups B2–B5 steel supports exposed to an air environment. The GALL Report recommends further evaluation of this structure and aging effect combination only if it is not covered by the Structures Monitoring Program. In the LRA, the applicant stated that this item does not require further evaluation because it is covered by the Structures Monitoring Program. The staff confirmed that the structure and aging effect combination is covered by the applicant’s Structures Monitoring Program and, therefore, finds the applicant’s determination acceptable. The staff’s review of the applicant’s Structures Monitoring Program is documented in SER Section 3.0.3.2.18.

(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, associated with LRA Table 3.5.1, item 3.5.1-40, addresses reduction in anchor capacity due to degradation of surrounding concrete for Groups B1–B5 supports exposed to an air environment. The GALL Report recommends further evaluation of this structure and aging effect combination only if it is not covered by the Structures Monitoring Program. In the LRA, the applicant stated that this item does not require further evaluation because it is covered by the Structures Monitoring Program.

The staff is concerned that the presence of ASR in the below-grade concrete may have impacted concrete anchor capacity. The reduction in concrete mechanical properties indicates that the anchor capacity would also be reduced. The Structures Monitoring Program has to be enhanced to account for this phenomenon. This is being tracked as Open Item OI 3.0.3.2.18-1.

Based on the information provided to date, and until OI 3.0.3.2.18-1 is resolved, the staff can not complete its evaluation of components associated with item 3.5.1-40.

(3) Reduction and Loss of Isolation Function due to Degradation of Vibration Isolation Elements for Group B4 Supports

LRA Section 3.5.2.2.2.6, associated with LRA Table 3.5.1, item 3.5.1-41, addresses reduction of isolation function of non-metallic vibration isolation elements in an air environment. In the LRA, the applicant stated that this item is not applicable because there are no vibration isolation elements within the scope of license renewal. The staff reviewed LRA Chapters 2 and 3 and confirmed that there are no in-scope vibration isolation elements; therefore, it finds the applicant's determination acceptable.

Cumulative Fatigue Damage due to Cyclic Loading. LRA Section 3.5.2.2.2.7 associated with LRA Table 3.5.1, item 3.5.1-42, states that analyses of fatigue of component support members, anchor bolts, and welds for Group B1.1, Group B1.2, and Group B1.3 component supports (for ASME Code Classes 1, 2, and 3 piping and components and for Class metal containment BWR containment supports) are TLAAs, as defined in 10 CFR 54.3, only if a CLB fatigue analysis exists. The staff confirmed that fatigue analyses for these components were not included as part of the CLB. This is consistent with SRP-LR Section 3.5.2.2.2.7 and is, therefore, acceptable.

3.5.2.2.3 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.5.2.3 Aging Management Review Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.5.2-1 through 3.5.2-8, 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 3.5.2-8, the applicant indicated, via Notes F–J that the combination of component type, material, environment, and AERM does not correspond to an 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 item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR 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 item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the 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 if the applicant 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.

3.5.2.3.1 Buildings, Structures within License Renewal—Summary of Aging Management Evaluation—LRA Table 3.5.2-1

In LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-5, 3.5.2-7, and 3.5.2-8, the applicant stated that roofing exposed to air-outdoor (external) is being managed for separation, environmental degradation, and water in-leakage by the Structures Monitoring Program. The AMR item cites generic note H and plant-specific note 505, which states that built-up roofing is not in the GALL Report; however, similar elastomeric materials, aging effects, and environments are identified under item III.A6-12, which recommends the Structures Monitoring Program.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because similar elastomeric materials are listed in the GALL Report in various environments, and the aging effects are loss of sealing and degradation of seals. The aging effects listed by the applicant for roofing exposed to an air-outdoor environment—separation, degradation, and in-leakage—are similar to the GALL Report identified aging effects.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. The staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because monitoring for this aging effect is done through periodic visual inspections, and the Structures Monitoring Program is the GALL Report recommended program for equivalent materials exposed to similar environments. The staff confirmed that roofing associated with this item is included in the scope of the Structures Monitoring Program.

In LRA Tables 3.5.2-1 and 3.5.2-8, the applicant stated that carbon steel revetment and carbon steel service water pumphouse components exposed to raw water are being managed for loss of material due to general (steel only), pitting, and crevice corrosion by the Structures Monitoring Program. The AMR item cites generic note H and plant-specific Notes 511 or 514. Plant-specific note 511 states that RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants (XI.S7)," is included under the Structures Monitoring Program (XI.S6). Plant-specific note 514 states that this condition will be managed through the Structures Monitoring Program.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because this is the aging effect listed in the GALL Report (item III.A6-11) for steel components exposed to raw water.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. The staff noted that the GALL Report, under item III.A6-11, identifies "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," as the recommended AMP for this material aging effect combination. The staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because it integrates the GALL Report recommended "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" AMP. Additionally, monitoring for this aging effect is done through periodic visual inspections in accordance with ANSI/ASCE 11-90, "Guideline for Structural Condition Assessment of Existing Buildings." The staff confirmed that steel components associated with this item are included in the scope of the Structures Monitoring Program.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.5.2.3.2 Containment Structures—Summary of Aging Management Evaluation—LRA Table 3.5.2-2

The staff's evaluation for built-up roofing exposed to air-outdoor environment, being managed for separation and degradation by the Structures Monitoring Program and citing generic note H and plant-specific note 505, is documented in SER Section 3.5.2.3.1.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.5.2.3.3 Fuel Handling and Overhead Cranes—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 fuel handling and overhead cranes.

The staff's review did not find any items indicating plant-specific notes F–J, whereby the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report.

The staff's evaluation of the items with notes A–E is documented in SER Section 3.5.2.1.

3.5.2.3.4 Miscellaneous Yard Structures—Summary of Aging Management Evaluation—LRA Table 3.5.2-4

In LRA Table 3.5.2-4, the applicant stated that aluminum SBO structures exposed to air-outdoor (external) are being managed for crack initiation and crack growth by the Structures Monitoring Program. The AMR item cites generic note H and plant-specific note 514.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because aluminum components that are exposed to outdoor air can experience crack initiation and growth. Aluminum components exposed to outdoor air can also experience loss of material; however, this aging effect has been addressed by the applicant and is being managed by the GALL Report recommended Structures Monitoring Program.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. The staff finds the applicant's proposal to manage cracking using the Structures Monitoring Program acceptable because monitoring for this aging effect is done through periodic visual inspections, which would detect this aging mechanism. In addition, the Structures Monitoring Program is the GALL Report recommended program for managing loss of material for aluminum components exposed to similar environments. The staff confirmed that aluminum components associated with this item are included in the scope of the Structures Monitoring Program.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.5.2.3.5 Primary Structures—Summary of Aging Management Evaluation—LRA Table 3.5.2-5

The staff's evaluation for built-up roofing exposed to air-outdoor environment, being managed for separation and degradation by the Structures Monitoring Program and citing generic note H and plant-specific note 505, is documented in SER Section 3.5.2.3.1.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.5.2.3.6 Supports—Summary of Aging Management Evaluation—LRA Table 3.5.2-6

In LRA Table 3.5.2-6, the applicant stated that ASME Class 2 and Class 3 stainless steel exposed to raw water (external) environment, are being managed for loss of material by the ASME Code Section XI, Subsection IWF Program. The AMR item cites generic note H and plant-specific note 514, which states that this condition will be managed through the Structures Monitoring Program.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because

ASME Class 2 and Class 3 stainless steel exposed to raw water (external) environment can experience loss of material. This is the same aging effect discussed in GALL Report item T-24, which is associated with ASME Class 2 and Class 3 steel exposed air. Although that item is a different material and environment, the aging effects are similar.

The staff confirmed that the structure and aging effect combination are covered by the ASME Code Section XI, Subsection IWF and the Structures Monitoring Programs. The staff's reviews of the applicant's ASME Code Section XI, Subsection IWF and the Structures Monitoring Programs are documented in SER Sections 3.0.3.1.10 and 3.0.3.2.18, respectively. The staff finds the applicant's proposal to manage aging using the ASME Code Section XI, Subsection IWF Structures Monitoring Programs acceptable because both programs use visual inspection that is capable of detecting loss of material.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

In LRA Table 3.5.2-6, the applicant stated that non-ASME constant and variable load spring hangers exposed to uncontrolled indoor air are being managed for loss of mechanical function by the Structures Monitoring Program. The AMR item cites generic note H and plant-specific note 514, which states that this condition will be managed through the Structures Monitoring Program.

The staff reviewed the associated items in the LRA and confirmed that the applicant identified the correct aging effects for this component, material, and environment combination because non-ASME constant and variable load spring hangers exposed to uncontrolled indoor air can experience loss of mechanical function. This is the same aging effect discussed in GALL Report item T-28, which is associated with ASME constant and variable load spring hangers. Although that item is associated with ASME components, the aging effects would be similar for non-ASME supports.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.18. The staff noted that, for ASME supports, the GALL Report recommends visual inspections under the IWF AMP to manage this aging effect. Since these are non-ASME supports, they are not within the scope of the IWF Program; however, the Structures Monitoring Program will use similar visual inspections to detect degradation. The staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because monitoring for this aging effect is done through periodic visual inspections in accordance with ANSI/ASCE 11-90, "Guideline for Structural Condition Assessment of Existing Buildings." The staff confirmed that non-ASME constant and variable load spring hangers associated with this item are included in the scope of the Structures Monitoring Program.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.5.2.3.7 Turbine Building—Summary of Aging Management Evaluation—LRA Table 3.5.2-7

The staff's evaluation for built-up roofing exposed to air-outdoor environment, being managed for separation and degradation by the Structures Monitoring Program and citing generic note H, is documented in SER Section 3.5.2.3.1.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.5.2.3.8 Water Control Structures—Summary of Aging Management Evaluation—LRA Table 3.5.2-8

The staff's evaluation for built-up roofing exposed to air-outdoor environment, being managed for separation and degradation by the Structures Monitoring Program and citing generic note H, is documented in SER Section 3.5.2.3.1.

The staff's evaluation for steel components exposed to a raw water environment, being managed for loss of material by the Structures Monitoring Program and citing generic note H, is documented in SER Section 3.5.2.3.1.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.5.3 Conclusion

Until Open Item OI 3.0.3.2.18-1 is resolved, the staff can not conclude that the applicant provided sufficient information to demonstrate that the effects of aging for the containments, 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 Aging Management of Electrical and Instrumentation and Controls

The following information documents the staff's review of the applicant's AMR results for the following electrical and instrumentation and control (I&C) components and commodity groups:

- non-EQ electrical cables and connections
- MEB
- fuse holders (not part of a larger assembly) metallic clamps
- cable connections (metallic parts)
- SF_6 insulated bus, connections, and insulators

3.6.1 Summary of Technical Information in the Application

LRA Section 3.6 provides AMR results for the electrical and I&C components and commodity groups. LRA Table 3.6.1, "Summary of Aging Management Evaluations for the Electrical/I&C Components/Commodities," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the electrical components, I&C components, and commodity groups.

3.6.2 Staff Evaluation

The staff reviewed LRA Section 3.6 to determine if 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 AMR 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 EQ requirements (3.6.1-1)	Degradation due to various aging mechanisms	EQ of Electric Components	Yes	TLAA EQ of Electric Components	EQ 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
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 Not Subject to 10 CFR 50.49 EQ Requirements Used In Instrumentation Circuits	No	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits	Consistent with GALL

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**
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 and 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
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	Boric Acid Corrosion	Consistent with GALL
Fuse holders (not part of a larger assembly) and 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	Yes	Fuse Holders	Consistent with GALL (See SER Section 3.6.2.3)
MEB—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
MEB—insulation/insulators (3.6.1-8)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	MEB	No	MEB	Consistent with GALL
MEB—enclosure assemblies (3.6.1-9)	Loss of material due to general corrosion	Structures Monitoring Program	No	Structures Monitoring Program	Consistent with GALL

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
MEB—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
High-voltage insulators (3.6.1-11)	Degradation of insulation quality due to presence of any salt deposits and surface contamination and loss of material caused by mechanical wear due to wind blowing on transmission conductors	A plant-specific AMP is to be evaluated	Yes	Not applicable	Not applicable to Seabrook (See SER Section 3.6.2.2.2)
Transmission conductors and connections and 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 Seabrook (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 EQ Requirements	No	Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements	Consistent with GALL
Fuse holders (not part of a larger assembly)—insulation material (3.6.1-14)	None	None	No	No AERM or AMP	Consistent with GALL

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
SF_6 insulated bus, connections and insulators—(insulation /insulators); (enclosure assemblies)	Loss of dielectric strength, loss of material, and hardening and loss of strength	None	Yes	345 kV SF_6 Bus	Consistent with GALL (See SER Section 3.6.2.3)

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 Aging Management Review Results 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 Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program
- Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program
- MEB Program
- Structures Monitoring Program
- Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Program
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program

In LRA Table 3.6.1, the applicant summarizes AMRs for the electrical and I&C 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 it does not recommend further evaluation, the staff's audit and review determined if the plant-specific components of these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant noted, for each AMR item, how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A–E, indicating how the AMR is consistent with the GALL Report.

Note A indicates that the AMR 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 items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR 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 items to verify consistency with the GALL Report and confirmed 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 item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, 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, in the GALL Report, a different component with the same material, environment, aging effect, and AMP as the component under review. The staff reviewed these items to verify consistency with the GALL Report. The staff also determined whether the AMR 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 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 items to verify consistency with the GALL Report. The staff confirmed whether the AMR item of the different component was applicable to the component under review and 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 item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff reviewed these 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's evaluation follows.

3.6.2.2 Aging Management Review Results 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 not subject to EQ, and provides information concerning how it will manage the following aging effects:

- 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
- increased resistance of connection due to oxidation or loss of pre-load

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 Table 3.6.1 of the LRA. 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

In LRA Section 3.6.2.2.1, associated with LRA Table 3.4.1, items 3.6.1-1, the applicant provides an evaluation of the EQ TLAA. 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 Deposit and Surface Contamination and Loss of Material due to Mechanical Wear

In LRA Section 3.6.2.2.2, associated with LRA Table 3.4.1, items 3.6.1-11, the applicant stated that the SF_6 switchyard connects Seabrook to the offsite transmission grid. The applicant also stated that the SF_6 bus is included as part of the recovery path in the event of an SBO event. The design of the SF_6 switchyard does not include high-voltage insulators that are commonly associated with an open-air switchyard design.

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.

During the LRA site audit, the staff performed a walk-down inspection to the switchyard and discussed the Seabrook switchyard design with the applicant's engineering staff. The staff noted that the Seabrook onsite distribution is connected to the offsite transmission grid via SF_6 buses. These buses provide the offsite recovery paths in an SBO event. The staff confirmed that there are no high-voltage insulators within the scope of license renewal. Therefore, the staff determined that degradation of insulator quality due to presence of salt deposits or surface contamination and loss of material due to mechanical wear is not applicable to Seabrook.

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 Pre-Load

In LRA Section 3.6.2.2.3, is associated with LRA Table 3.4.1, items 3.6.1-12, the applicant stated that the SF_6 switchyard connects Seabrook to the offsite transmission grid. The applicant also stated that the in-scope portion of the SF_6 switchyard does not include transmission conductors and connections or switchyard bus and connections that are commonly associated with an open-air switchyard design.

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 pre-load 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.

During the LRA site audit, the staff performed a walk-down inspection to the switchyard and discussed the Seabrook switchyard design with the applicant's engineering staff. The staff noted that the SF_6 buses are used to connect the Seabrook onsite distribution to the offsite transmission grid. The enclosed SF_6 buses provide the offsite recovery paths in an SBO event. The staff confirmed that there are no transmission conductors and switchyard bus within the scope of license renewal. Therefore, the staff determined 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 pre-load is not applicable to transmission conductors and connections and switchyard bus and connections at Seabrook.

3.6.2.3 Aging Management Review Results 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–J that the combination of component type, material, environment, and AERM does not correspond to an 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 if the applicant 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.

3.6.2.3.1 Electrical and I&C Components and Commodities—Summary of Aging Management Review—LRA Table 3.6.2-1

In LRA Section 3.6.2.3, the applicant stated that the 345 kV SF_6 switchyard connects Seabrook to the offsite transmission grid. The SF_6 bus is included as part of the recovery path in the event of an SBO event. The applicant also stated that, as discussed in LRA Sections 3.6.2.2.2 and 3.6.2.2.3, the design of the SF_6 switchyard does not include high-voltage insulators and transmission lines that are normally associated with an open-air switchyard. The SF_6 bus is a phase isolated and independent bus in which each phase conductor is enclosed by an individual metal housing separated from adjacent conductor housings by an air space. The conductor is centered in the housing by insulators. The insulating parameters are accomplished by maintaining the space achieved by the insulators and the insulating properties of the SF_6 gas. The applicant further stated that the critical conditions, which are essential to the bus operation, are maintaining the pressure boundary and the air, moisture and SO_2 content. The applicant stated that presence of moisture could lead to electrical failure, and the presence of SO_2 is an indication of partial discharge in the system. The external surface of the SF_6 bus is managed for loss of material. The pressure boundary and the quality of the SF_6 gas are managed by the 345 kV SF_6 Bus AMP.

The staff noted that the potential aging effects on the 345 kV SF_6 bus are the loss of pressure boundary due to elastomer degradation; loss of material due to pitting, crevice, and galvanic corrosion; and loss of bus intended function due to unacceptable air, moisture, or SO_2 levels. The SF_6 is an inert gas used to insulate the bus conductor. The applicant will inspect for corrosion on the exterior of the bus duct housing, test for leaks at elastomers, and periodically test gas samples to determine air, moisture, and SO_2 level. The staff determined that these inspections are acceptable because they will maintain the insulating properties of the SF_6 gas by maintaining the pressure boundary and monitoring the SF_6 air, moisture, and SO_2 content. The staff evaluation of this program is provided in SER Section 3.0.3.3.2.

In the Seabrook LRA, Table 3.6.1, item 3.6.1-6, “Fuse Holders (Not Part of a Larger Assembly; Fuse holders—Metallic Clamp)” and AMP B.2.1.36, “Fuse Holders,” the applicant states that the thermal fatigue in the form of high resistance caused by ohmic heating, thermal cycling or electrical transients, and mechanical fatigue caused by frequent removal of the fuse or vibration are not aging mechanisms requiring aging management based on the Seabrook analysis. Although the applicant concludes in LRA Table 3.6.1, item 3.6.1-6, and LRA Section B.2.1.36 that the aging effects and mechanisms due to thermal fatigue and mechanical fatigue identified by GALL are not applicable to the fuse holders at Seabrook, the applicant does not provide information to substantiate its conclusion. GALL Report, Volume 2, Revision 1, item VI.A-8, “Fuse Holders (Not Part of a Larger Assembly—Metallic Clamp),” identifies the aging effect and mechanism as fatigue and ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, and oxidation.

During the Seabrook LRA audit, the week of October 21, 2010, the staff requested the applicant provide an analysis of why the aging effects and mechanism due to thermal fatigue in form of high resistance caused by ohmic heating, thermal cycling or electrical transients, and mechanical fatigue caused by frequent removal or replacement of the fuse or vibration, identified in GALL Report, Volume 2, Revision 1, item VI.A-8, are not applicable to the fuse holders at Seabrook. In a letter dated November 15, 2010, the applicant provided the following Seabrook analysis to justify why the aging effects due to thermal fatigue in the form of high resistance caused by ohmic heating, and thermal cycling, electrical transients, mechanical fatigue caused by frequent manipulation, vibration, and chemical contamination do not require aging management:

- Ohmic Heating and Thermal Cycling—Seabrook power circuits are sized so that the ohmic heating is approximately 60 percent of the cable rated temperature. Therefore, ohmic heating of the fuse clamps is minimized.
- Electrical Transient—Seabrook electrical design ensures that stress due to forces associated with electrical faults and transients are mitigated by the fast action of circuit protective devices at high fault currents. Mechanical stress due to electrical faults is not considered a credible aging mechanical since such faults are infrequent and random in nature. Electrical transients are not considered an aging mechanism that requires management.
- Frequent Manipulation—In review of the Seabrook operation database, of all in-scope fuses that are held in place by metallic (non-bolted) fuse clips, only seven have been

pulled during the life of the plant. Therefore, frequent manipulation of in-scope fuses is not considered an aging mechanism that requires management.

- Vibration—Seabrook design drawings and documentation determined the exact location and mounting of the fuse holders within the scope of this evaluation. This documentation verifies that there are no direct sources of vibration in proximity to the fuse holder junction boxes. The fuse holder junction boxes are mounted to a support attached directly to either a concrete wall or a column. Therefore, vibration is not considered an aging mechanism that requires management.
- Chemical Contamination—The location and mounting of the fuse holders within scope have no potential sources of chemical contamination in the area, and the fuse holders are housed in a protective enclosure to preclude this aging mechanism even if chemical contamination were possible. Therefore, based on their installed location and design configuration, chemical contamination is not considered an aging mechanism that requires management.

Based on its analysis, the Fuse Holder Program description, in LRA Section B.2.1.36, was revised by the applicant to clarify the exclusion of the above aging mechanisms from the Fuse Holder Program. Based on the staff's review of the applicant's analysis and revised LRA Section B.2.1.36 program description and staff confirmatory walkdown of the in-scope fuse holders, the staff finds the applicant's response acceptable because the applicant provided adequate justification to exclude the above aging mechanisms from the Fuse Holder Program.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant 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).

3.6.3 Conclusion

The staff concludes that 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).

3.7 Conclusion for AMR 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 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).

SECTION 4

TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

Certain plant-specific safety analyses involve time-limited assumptions defined by the current operating term. Pursuant to Section 54.21(c)(1) of Title 10 of the *Code of Federal Regulations* (10 CFR 54.21(c)(1)), applicants must list those analyses in the current licensing basis (CLB) that meet the definition of a time-limited aging analysis (TLAA), as defined in 10 CFR 54.3.

In addition, pursuant to 10 CFR 54.21(c)(2), applicants must list plant-specific exemptions, granted under 10 CFR 50.12, that are based on TLAAs. For any such exemption, the applicant must evaluate and justify the continuation of the exemption for the period of extended operation.

This section of the safety evaluation report (SER) provides the staff's evaluation of the applicant's basis for identifying those plant-specific or generic analyses that need to be identified as TLAAs for the license renewal application (LRA). This section of the SER also provides the staff's evaluation of the applicant's basis for concluding that the applicant's LRA includes all exemptions that are based on a TLAA.

The U.S. Nuclear Regulatory Commission's (NRC's) guidance on matters related to the identification of TLAAs and TLAA-related exemptions is given in NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR) Section 4.1. The staff's recommended "acceptance criteria" guidance is given in SRP-LR Section 4.1.2, and the staff's recommended "review procedure" guidance is given in SRP-LR Section 4.1.3.

4.1.1 Summary of Technical Information in the Application

LRA Section 4.1 provides the basis for identifying the applicant's analyses as TLAAs in accordance with 10 CFR 54.21(c)(1). The applicant stated that it evaluated those calculations that complied with the six criteria for defining an analysis as a TLAA, as specified in 10 CFR 54.3. The list of TLAAs provided in LRA Table 4.1-1 meet the six criteria of a TLAA. The applicant stated that it reviewed the list of common TLAAs in the SRP-LR, dated September 2005. The applicant also stated that its review of the CLB included a review of the updated final safety analysis report (UFSAR), docketed licensing correspondence, design bases documents, applicant engineering calculations, applicable Westinghouse Owner's Group (WOG) reports, technical specifications (TS) and TS bases documents, and previous applicants' LRAs.

Pursuant to 10 CFR 54.21(c)(2), the applicant stated that it did not identify any exemptions that were granted under 10 CFR 50.12 and are based on a TLAA, as defined in 10 CFR 54.3.

4.1.2 Staff Evaluation

For each analysis identified as a TLAA in accordance with the requirements of 10 CFR 54.21(c)(1), the applicant shall demonstrate that the TLAA is acceptable in accordance with one of following TLAA acceptance criteria:

(i) The analysis remains valid for the period of extended operation.

(ii) The analysis has been projected to the end of the period of extended operation.

(iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

LRA Section 4.1.2 provides the applicant's methodology for determining which analyses in the CLB need to be identified as TLAAs. LRA Table 4.1-1 identifies those TLAAs that are applicable and provides the applicable sections that discuss these TLAAs. LRA Section 4.1-2 identifies if the generic analyses in SRP-LR Tables 4.1-2 and 4.1-3 are applicable to the applicant's CLB and if they need to be identified as TLAAs. LRA Section 4.1.3 discusses the exemptions that need to be identified in accordance with the exemption identification requirement in 10 CFR 54.21(c)(2). The staff reviewed this information against the NRC guidance in SRP-LR Section 4.1 to determine if the applicant provided sufficient information pursuant to TLAA identification requirements in 10 CFR 54.21(c)(1) and exemption identification requirements in 10 CFR 54.21(c)(2).

4.1.2.1 Evaluation of the Applicant's Identification of TLAAs

As defined in 10 CFR 54.3, an analysis in the CLB meets the definition of a TLAA if it meets the following criteria:

(1) involves systems, structures, and components (SSCs) within the scope of license renewal as described in 10 CFR 54.4(a)

(2) considers the effects of aging

(3) involves time-limited assumptions defined by the current operating term (for example, 40 years)

(4) is determined to be relevant by the applicant in making a safety determination

(5) involves conclusions, or provides the basis for conclusions, related to the capability of the SSC to perform its intended functions, as described in 10 CFR 54.4(b)

(6) is contained or incorporated by reference in the CLB

The staff's Statement of Consideration (SOC) for 10 CFR Part 54, in Section III.g.(i) of Nuclear Power Plant License Renewal; Final Rule 60 FR 22461, 22479-22481 (May 8, 1995), provides additional clarification on when an analysis in the CLB needs to be identified as a TLAA.

The staff noted that LRA Table 4.1-1 identifies those analyses in the applicant's CLB that meet the definition of a TLAA in 10 CFR 54.3. The staff's evaluation of the applicant's disposition for these TLAAs, in accordance with 10 CFR 54.21(c)(1), are documented in the applicable subsections of SER Section 4. The staff also noted that, in LRA Tables 4.1-1 and 4.1-2, the applicant identified the following analyses in the CLB that do not meet the definition of a TLAA:

- **4.3 Metal Fatigue Analysis**
  - 4.3.2.1 Thermal Stresses in Piping Connected to RCS: NRC Bulletin 88-08
  - 4.3.6 Fatigue Crack Growth, Fracture Mechanics Stability, or Corrosion Analyses Supporting Repair of Alloy 600 Materials
- **4.5 Concrete Containment Tendon Prestress**

- **4.7 Plant-Specific Time-Limited Aging Analyses**
  - 4.7.1 Reactor Pressure Vessel (RPV) Underclad Cracking Analyses
  - 4.7.8 Reactor Coolant Pump: Code Case N-481
  - 4.7.12 Metal Corrosion Allowance
  - 4.7.13 Inservice Flaw Growth Analyses that Demonstrate Structural Stability for 40 years

For each of these analyses, the applicant's conclusion that the analysis is not a TLAA was reviewed against the applicant's CLB and the criteria of a TLAA. The staff's review was performed in accordance with the review procedures in SRP-LR Section 4.1.3 and the acceptance criteria in SRP-LR Section 4.1.2, considering the clarification in Section III.g.(i) of the SOC for 10 CFR Part 54 (60 FR 22, 479-81). The staff's review and findings for each item are provided in the SER section indicated.

4.1.2.2 Evaluation of the Applicant's Identification of those Exemptions in the CLB that are based on TLAAs

As required by 10 CFR 54.21(c)(2), the applicant must list all exemptions granted under 10 CFR 50.12 that are based on TLAAs and then provide an evaluation that justifies the continuation of these exemptions through the period of extended operation. LRA Section 4.1.3 states that the UFSAR, the facility operating license, the SER and associated supplements, and all docketed correspondence were reviewed for active exemptions granted under 10 CFR 50.12 to determine if these exemptions were based on TLAAs. The applicant stated that no active exemptions, granted pursuant to 10 CFR 50.12 and based on a TLAA, have been identified.

The staff reviewed the following documents to verify if there were exemptions in the CLB, granted in accordance with 10 CFR 50.12, that were based on a TLAA:

- Seabrook Station (Seabrook), Unit No. 1, Facility Operating License No. NPF-86
- applicable exemptions on neutron irradiation embrittlement analyses, requested pursuant to requirements in 10 CFR 50.60(b) and granted under the requirements in 10 CFR 50.12

The staff noted that, on November 12, 2002, the applicant requested an exemption from compliance with the pressure-temperature (P-T) limit generation requirements of 10 CFR Part 50, Appendix G. The applicant requested this exemption in accordance with 10 CFR 50.60(b) for NRC approval to use ASME Code Case N-641 as the basis for generating its P-T limit curves. The staff granted this exemption in accordance with 10 CFR 50.12 by its safety evaluation (SE) and exemption approval letter to the applicant dated August 1, 2003. The staff noted that this exemption allows the applicant to generate the P-T limit curves using the adjusted reference temperature (ART) equation for a K_{Ic} linear elastic fracture toughness criterion. The staff also noted that this exemption has a specific relationship to the applicant's generation of its P-T limit curves, which is identified as a TLAA and is documented in LRA Section 4.2.4. Therefore, the staff noted that this exemption may need to be identified in accordance with 10 CFR 54.21(c)(2).

By letter dated January 5, 2011, the staff issued RAI 4.1-3, requesting the applicant to clarify and justify whether this exemption needs to be identified in accordance with 10 CFR 54.21(c)(2) and if continuation of the exemption will be needed for the period of extended operation. In its response dated February 3, 2011, the applicant stated that a discussion of this exemption should have been included in LRA Section 4.1.3; however, the conclusion stated in LRA Section 4.1.3 remains unchanged. In response to RAI 4.1-3, the applicant added the following to the “Analysis” section of LRA Section 4.1.3:

> On November 12, 2002, Seabrook Station requested an exemption from compliance with the pressure-temperature (P-T) limit generation requirements of 10 CFR Part 50, Appendix G. Seabrook Station requested this exemption in accordance with 10 CFR 50.60(b), specifically, requesting NRC approval to use ASME Code Case N-641 as the basis for generating its P-T limit curves. The NRC staff granted this exemption in accordance with 10 CFR 50.12 by its safety evaluation and exemption approval letter dated August 1, 2003.

The applicant also stated in its response to RAI 4.1-3 that the exemption for use of the K_{IC} curve is not based on a TLAA because the reference toughness curve will not change with time. The applicant added that the effects of neutron fluence on the RPV beltline materials must be monitored, and the aging effects due to neutron irradiation are managed as a TLAA under LRA Section 4.2.4 by the Reactor Vessel Surveillance Program. However, the applicant stated that any changes in the fracture toughness properties of the limiting vessel materials would not affect the continuation of the exemption to use Code Case N-641 for the period of extended operation, which serves as the basis for generating the applicant’s P-T limit curves (refer to LRA Section 4.2.4 and SER Section 4.2.4). The applicant further added that Regulatory Issue Summary (RIS) 2004-04 indicates that the use of NRC-approved ASME Code Cases in conjunction with earlier versions of the ASME Code endorsed in 10 CFR 50.55a may also be used for development of P-T limit curves without the need for an exemption.

The staff reviewed the information in RIS 2004-04 and determined that it identifies that exemptions are no longer necessary for implementation of the methodology in ASME Code Case N-641. In addition, the staff confirmed that the methodology in ASME Code Case N-641 is currently endorsed for use in RG 1.147; thus, 10 CFR 50.55a(b)(5) and RG 1.147 no longer require an exemption for implementation of the Code Case methodology.

Based on the review, the staff finds the applicant’s response to RAI 4.1-3, and the applicant’s conclusion that this exemption does not need to be included in the LRA, acceptable because an exemption is no longer required for application of the Code Case methodology to the P-T limits. The staff’s evaluation of the P-T limits is documented in SER Section 4.2.4. The staff’s concern described in RAI 4.1-3 is resolved.

Based on the information provided by the applicant regarding the process used to identify these exemptions and its results, the staff concludes that, in accordance with 10 CFR 54.21(c)(2), there are no TLAA-based exemptions that need to be justified for continuation through the period of extended operation.

4.1.3 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable list of TLAAs, as required by 10 CFR 54.21(c)(1). The staff confirmed, as required by 10 CFR 54.21(c)(2), that no exemptions exist in the CLB that have been granted pursuant to 10 CFR 50.12 and have been based on a TLAA.

4.2 Reactor Pressure Vessel Neutron Embrittlement

The regulations governing RPV integrity are in 10 CFR Part 50, which requires that all light-water reactors must comply with the fracture toughness requirements for the reactor coolant pressure boundary (RCPB), including those for upper-shelf energy (USE) analyses and P-T limit analyses, as set forth in 10 CFR Part 50, Appendix G. Light-water reactors must also comply with the Reactor Vessel Surveillance Program requirements for the RCPB, as set forth in 10 CFR Part 50, Appendix H. In addition, licensees of pressurized-water reactor (PWR)-plants are required to perform analyses for prevention of pressurized thermal shock (PTS) events, consistent with the PTS requirements of 10 CFR 50.61 or the alternative PTS requirements of 10 CFR 50.61a. The Seabrook CLB analyses of RPV fracture toughness reduction due to neutron embrittlement for 40 years are TLAAs.

The NRC's recommended "acceptance criteria" and "review procedure" guidance related to the acceptance of TLAAs on RPV neutron embrittlement are given in SRP-LR Section 4.2 and its subsections. For USE analyses, the recommended "acceptance criteria" guidance is given in SRP-LR Section 4.2.2.1.1, and the recommended "review procedure" guidance is given in SPR-LR Section 4.2.3.1.1. For PWR PTS analyses or alternative PTS analyses, the recommended "acceptance criteria" guidance is given in SRP-LR Section 4.2.2.1.2 and the recommended "review procedures" are given in SPR-LR Section 4.2.3.1.2. For P-T limit analyses, the recommended "acceptance criteria" guidance is given in SRP-LR Section 4.2.2.1.3, and the recommended "review procedure" guidance is given in SPR-LR Section 4.2.3.1.3. These SRP-LR "acceptance criteria and "review procedures" sections are subdivided into sections that provide the staff's guidance for dispositioning these TLAAs in accordance with 10 CFR 54.21(c)(1)(i), 10 CFR 54.21(c)(1)(ii), or 10 CFR 54.21(c)(1)(iii).

4.2.1 Reactor Pressure Vessel Fluence

4.2.1.1 Summary of Technical Information in the Application

LRA Section 4.2.1 summarizes the evaluation of reactor vessel fluence for the period of extended operation, projecting neutron exposure levels for the RPVs for an operating period extending to 55 effective full-power years (EFPY).

The applicant states that the current license period reactor vessel embrittlement analyses, which evaluate the reduction of fracture toughness properties for the Seabrook reactor vessel beltline materials, are based on predicted 40-year EOL fluence values. The applicant states that the neutron fluence analysis and the neutron embrittlement analyses, which are based upon the fluence analysis, are TLAAs, as defined by 10 CFR 54.21(c)(1). The applicant states that these TLAAs must be evaluated for the increased neutron fluence associated with 60 years of operation. The applicant states that the TLAAs impacted by the neutron fluence analysis include the analyses for evaluating the ductile fracture toughness of the reactor vessel beltline components (i.e., USE analysis), protecting the reactor vessel against PTS events (PTS assessment), and the P-T limits analysis and low temperature overpressure protection (LTOP) analysis that is dependent on the P-T limits analysis. The applicant states that these fracture toughness property-related analyses are discussed in LRA Sections 4.2.2, 4.2.3, and 4.2.4.

The applicant stated that the end-of-life fluence is based on a predicted value of EFPY over the life of the plant. As of October 30, 2009, Seabrook Station has been operated for approximately 17 EFPY. If Seabrook Station is operated at the maximum licensed power level at a 100% capacity factor between outages until the end of period of extended operation on

March 15, 2050, Seabrook Station will reach approximately 55 EFPY. This capacity factor is based on assumed outage durations of twenty (20) days during refueling outages and 100 percent power levels at all times other than during these outages. For license renewal, Seabrook Station updated fluence projections based upon 55 EFPY as input, to the neutron embrittlement analyses prepared for 60 years of operation.

The applicant also stated that the fluence values were calculated using the RAMA Fluence Methodology (RAMA). The RAMA Fluence Methodology was developed for the Electric Power Research Institute, Inc. (EPRI) for the purpose of calculating fast neutron fluence in reactor pressure vessels and vessel internal components. As prescribed in NRC Regulatory Guide 1.190, RAMA has been benchmarked against industry standard benchmarks for both pressurized water reactor (PWR) and boiling water reactor designs. In addition, RAMA has been compared with several plant-specific dosimetry measurements and reported fluence from several commercial operating reactors. The results of the benchmarks and comparisons to measurements show that RAMA accurately predicts specimen activities, RPV fluence, and vessel component fluence in all light water reactor types. Under funding from EPRI and the Boiling Water Reactor Vessel and Internals Project, the RAMA methodology has been reviewed by the NRC and subsequently given generic approval for determining fast neutron fluence in boiling water reactor pressure vessels and vessel internal components that include the core shroud and top guide. This prior work has been extended in the Seabrook Station analysis to additional PWR benchmarks and plant-specific dosimetry comparisons, further validating the use of RAMA for all light water reactor designs.

The applicant provided its updated 60-year (55 EFPY) reactor vessel inside surface fluences for the reactor vessel beltine materials in LRA Table 4.2.1-1. In this TLAA, the applicant states that the 55 EFPY neutron fluence values for the Seabrook reactor vessel have been projected to the end of the period of extended operation and that the 55 EFPY neutron fluences are, therefore, acceptable in accordance with the criterion in 10 CFR 54.21(c)(1)(ii).

4.2.1.2 Staff Evaluation

The staff reviewed LRA Section 4.2.1 to verify, pursuant to 10 CFR 54.21(c)(1)(ii), that the neutron fluence analyses have been projected to the end of the period of extended operation.

The staff noted that the applicant stated that the methodology for calculating the Seabrook neutron fluence values complies with the staff recommendations that are provided in RG 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” The applicant is using the RAMA methodology to calculate the 55 EFPY neutron fluence values (in terms of n/cm^2 (E > 1.0 MeV)) for the Seabrook reactor vessel beltline components. The RAMA methodology, while approved by the NRC to calculate fluence values for boiling-water reactor (BWR) vessel beltline components, has not explicitly been approved to calculate fluence values for PWR geometries.

The staff requested additional information in light of the following excerpt from the application: “This prior work has been extended in the Seabrook Station analysis to additional PWR benchmarks and plant-specific dosimetry comparison, further validating the use of RAMA for all light water reactor designs.”

Specifically, RAI 4.2.1-1 requested that the applicant provide documentation of the referenced additional PWR benchmarks and plant-specific dosimetry comparisons to demonstrate adherence to the regulatory positions contained in RG 1.190. In response, the applicant stated the following:

> In accordance with the requirements of Regulatory Position 1.4 of Regulatory Guide 1.190, the RAMA Fluence Methodology has been previously qualified using accepted benchmarks prescribed in RG 1.190. Results from the qualification effort are presented in Reference 1, BWRVIP-115-A: BWR Vessel and Internals Project, RAMA Fluence Methodology Benchmark Manual - Evaluation of Regulatory Guide 1.190 Benchmark Problems, EPRI, Palo Alto, CA: 2009. 1019050. [1019050NP (ADAMS Accession ML100540367)] and have been reviewed and accepted by the Staff for application of the RAMA Fluence Methodology to boiling water reactor fluence evaluations. The qualifications include comparisons to calculated results for the Pool Critical Assembly (PCA) and the VENUS-3 vessel simulation benchmarks, comparisons to the H. B. Robinson Unit 2 pressure vessel benchmark, and comparisons to the BWR calculational benchmark. In support of the Seabrook Station fluence evaluation, the qualifications for the RAMA Fluence Methodology are herein extended to include comparisons to the PWR calculational benchmark and comparisons to plant-specific activation measurements from three surveillance capsules irradiated in Seabrook Station.

The applicant submitted SEA-FLU-001-R-003, Revision 0, "Licensing Version of Seabrook Station Reactor Pressure Vessel Fluence Evaluation at 55 EFPY," which contains the results of plant-specific Seabrook surveillance capsule evaluations described above, and TWE-FLU-001-R-001, Revision 0, "RAMA Fluence Methodology—Evaluation of Regulatory Guide 1.190 PWR Calculational Benchmark," which documents the comparisons to the PWR calculational benchmark.

The applicant's response continues as follows:

> Section 6 of SEA-FLU-00 1 R-003 provides an assessment of the uncertainty in the RPV fast neutron fluence predictions for Seabrook Station in accordance with RG 1.190, accounting for all experimental, benchmark and plant-specific evaluations. The following paragraphs provide a summary of the RAMA benchmark and plant-specific comparisons.
>
> The PCA benchmark consists of 27 measurements spanning five different fast neutron reactions. The VENUS-3 benchmark consists of 385 measurements from three fast neutron reactions. The RAMA calculation-to-measurement (C/M) comparisons to the PCA and VENUS-3 vessel simulation benchmarks are 0.99 with a standard deviation of ±0.05 and 1.03 with a standard deviation of ±0.05, respectively. Details of the RAMA models and comparisons for the two vessel simulation benchmarks are provided in BWRVIP-115-A.
>
> The H. B. Robinson Unit 2 benchmark consists of activation measurements obtained from an in-vessel surveillance capsule and a cavity dosimeter after one cycle (cycle 9) of operation. The RAMA C/M comparisons to the H. B. Robinson Unit 2 pressure vessel benchmark for the surveillance capsule and cavity dosimeter are 0.95 with a standard deviation of ±0.04 and 1.04 ±0.04, respectively. Details of the RAMA model and comparisons for the H. B. Robinson benchmark are provided in BWRVIP-115-A.

> The PWR calculational benchmark consists of fast neutron flux predictions and capsule reaction rate estimates obtained from a discrete ordinates model of a typical PWR reactor geometry. Three core loading configurations are included in the benchmark: a standard core loading, a low leakage core loading, and a partial length shield assembly loading. The average RAMA comparisons to the discrete ordinates results are 1.12 with a standard deviation of ±0.11 for the standard core loading and 1.02 with a standard deviation of ±0.12 for the low leakage core loading. The RAMA-predicted reduction in fast neutron flux for the partial length shield assembly loading is 1.01 with a standard deviation of ±0.03 when compared to the corresponding reduction from the discrete ordinates solution. Details of the RAMA models and comparisons for the PWR calculational benchmark are provided in TWE-FLU-001-R-001.
>
> Plant-specific activation measurements have been performed for three surveillance capsules removed from Seabrook Station after being irradiated for one cycle, five cycles, and ten cycles. The average comparisons of RAMA-predicted activation to measurements (C/M) for each of the three Seabrook Station capsules are 1.08 ± 0.08, 1.05 ± 0.06, and 1.07 ± 0.09. Details of the RAMA models and comparisons are provided in SEA-FLU-001-R-003, Rev. 0.

The staff notes that the applicant stated, in summary, the following:

- The RAMA methodology is qualified against industry-standard benchmarks, including the PCA, VENUS-3, and H. B. Robinson Unit 2 pressure vessel benchmark problems. This qualification is NRC staff-approved, as documented in BWRVIP-115A.
- The RAMA methodology was further qualified by comparison to the PWR benchmark problems. This qualification considers three different core loading patterns, and it is effectively a code-to-code comparison since it consists of discrete ordinates transport solutions.
- The RAMA methodology was also qualified against Seabrook-specific capsule dosimetry, which included three surveillance capsules removed at various points in the Seabrook operating lifetime.

RG 1.190 recommends that calculational methodology be qualified by comparisons to measurements and calculational benchmarks, that the calculational bias and uncertainty be determined by appropriate combination of both analytic and measurement uncertainty, and that the vessel fluence calculational uncertainty be demonstrated to be less than or equal to 20 percent. While the staff previously reviewed the PCA, VENUS-3, and H. B. Robinson benchmarks, the staff presently considered the PWR benchmark problem solutions and the plant-specific dosimetry comparisons in its review of the LRA.

The PWR calculational benchmark problems are described in detail in NUREG/CR-6115, "PWR and BWR Pressure Vessel Fluence Calculation Benchmark Problems and Solutions." The applicant demonstrated that the benchmark comparisons agreed with acceptable comparison ratios in that agreement was within the 20 percent specified in RG 1.190. The staff notes that, while standard deviations and comparison ratios, combined together, may have in cases exceeded a total of 20 percent (i.e., the ratio for the standard core loading was 1.12±0.11), the staff also notes that the comparison is based on two separate numerical techniques and that the applicant's method relies on slightly more sophisticated techniques than those contained in the benchmark solutions. The comparison, therefore, incorporates the uncertainties and biases of two methods, not solely those associated with RAMA. Based on these considerations, the staff considers the comparison to demonstrate good agreement, and the staff finds the applicant's comparisons to be in accordance with RG 1.190 guidance.

The staff notes that the Seabrook capsule dosimetry comparisons demonstrate good agreement, within the 20 percent specified in RG 1.190, and have no readily discernible bias.

Based on its review of the information provided by the applicant, the NRC staff finds that the RAMA method was suitably qualified to perform fluence calculations for the Seabrook reactor vessel beltline materials. The staff's finding is based on the fact that the information provided by the applicant demonstrated that the RAMA method adheres to RG 1.190 guidance for comparison to benchmark problems and plant-specific dosimetry.

The staff also reviewed the reports referenced above by the applicant, including SEA-FLU-001-R-003. In addition to documenting the surveillance capsule dosimetry qualification, this report also describes the treatment of the Seabrook power history. The report states that reactor operating data inputs were developed from plant records and core simulator data that provided a historical accounting of how the reactor operated for cycles 1–12. The report also detailed how future cycles would be modeled. Based on its review of the information contained in the report, the staff finds that the applicant's fluence calculations adequately account for past, present, and planned facility operation through the duration of the extended operation.

The NRC staff finds the applicant's fluence calculations acceptable to support the requested renewed facility operating license based on the following:

- The RAMA methodology is generically approved by the NRC staff for BWRs and PWRs.
- RAMA has been adequately benchmarked for analysis of the Seabrook reactor vessel.
- The fluence calculations account for past, present and planned facility operation.

Pursuant to 10 CFR 54.21(c)(1)(ii), the applicant has projected the fluence values to 55 EFPY, which represents the end of the period of extended operation.

4.2.1.3 FSAR Supplement

The applicant provided a final safety analysis report (FSAR) supplement summary description of its TLAA evaluation of reactor vessel neutron fluence in LRA Section A.1.2.1.1. On the basis of its review of the FSAR supplement, the staff concludes that the summary description of the applicant's actions to address reactor vessel neutron fluence is adequate.

4.2.1.4 Conclusion

On the basis of its review, the staff concludes that, pursuant to 10 CFR 54.21(c)(1)(ii), the applicant has demonstrated that the analyses for reactor vessel neutron fluence have been projected to the end of the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.2 Upper Shelf Energy Analyses

4.2.2.1 Summary of Technical Information in the Application

LRA Section 4.2.2 summarizes the applicant's evaluation of Charpy USE values for the period of extended operation. The applicant dispositions this TLAA in accordance with 10 CFR 54.21(c)(1)(ii), having projected the Charpy USE using the 55 EFPY fluences described in Section 4.2.1 of the LRA, as attenuated to the one-quarter-thickness (¼T) location in the RPV wall.

The application states that the Charpy USE for all of the beltline materials of the Seabrook RPV were determined according to RG 1.99, Revision 2, without the use of surveillance data (Position 1.2 of the RG). The application further states that this approach gave lower (more conservative) projections for the USE at the end of the 60-year period of extended operation than the alternative using surveillance data (Position 2.2 of the RG), and the projected USE values for the beltline and extended beltline materials remain above the 50 foot-pound (ft-lb) requirement of Appendix G of 10 CFR Part 50 through the period of extended operation, as indicated in LRA Table 4.2.2-1.

4.2.2.2 Staff Evaluation

The staff reviewed LRA Section 4.2.2 to verify that the Charpy USE analyses have been acceptably projected to the end of the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(ii) and consistent with SRP-LR Section 4.2.2.1.1.2.

Appendix G to 10 CFR Part 50 contains the screening criteria that establish limits on the USE values for RPV materials after neutron irradiation exposure. The regulation requires the value of USE to be greater than 50 ft-lbs in the irradiated condition throughout the licensed life of the plant. USE values of less than 50 ft-lbs may be acceptable to the staff if the licensee can demonstrate that these lower values will provide margins of safety against brittle fracture equivalent to those required by ASME Code, Section XI, Appendix G.

RG 1.99, Revision 2, provides two methods to determine the projected decrease in USE for an RPV material as a function of the neutron fluence for the material. RG Position 1.2 uses curves that characterize decrease in USE as a function of the material copper (Cu) content and neutron fluence, without specific consideration of the surveillance data for the material. RG Position 2.2 uses reactor surveillance data to estimate decrease of USE. LRA Section 4.2.2.1 states that the applicant used RG Position 1.2 to determine the Charpy USE values at the end of the period of extended operation for the RPV materials because RG Position 1.2 projected lower (more conservative) USE values for each of these materials.

For the RPV beltline materials, the staff performed its evaluation using the NRC's Reactor Vessel Integrity Database (RVID). The staff found that the Cu content and unirradiated USEs for Seabrook RPV beltline materials in LRA Table 4.2.2-1 are almost identical to those in the RVID. The discrepancies did not significantly impact the USE evaluations for the subject welds. However, because RVID does not contain information for the extended beltline materials, the staff requested (part of RAI 4.2.2-1) that the applicant describe the procedures used to determine the chemistry data, initial RT_{NDT}, margins, and initial USE values for the extended beltline materials. The applicant was asked to demonstrate that it has applied consistent approaches for both the beltline and the extended beltline materials.

The applicant's February 3, 2011, response provided additional information from certified material test records (CMTRs), original equipment manufacturer (OEM) certified letter reports, and the Seabrook UFSAR supporting the chemistry and unirradiated USE values in LRA Table 4.2.2-1. The staff considers these sources of the information for the extended beltline materials to be similar to those that are used for the beltline materials. Hence, consistent approaches have been used to determine the material information for both beltline and extended beltline materials, and the part of RAI 4.2.2-1 related to USE projections is resolved.

The staff confirmed the applicant's projected USE values at the end of the period of extended operation for beltline and extended beltline materials by using Position 1.2 of RG 1.99, Revision 2. The staff's analysis verified that the lower shell plate B1808-2 was the limiting material with a projected USE value of 59 ft-lbs after 56 EFPY.

To summarize, the staff determined that all of the Seabrook RPV extended beltline materials have projected USE values at ¼T greater than 50 ft-lbs. Pursuant to 10 CFR 54.21(c)(1)(ii), these USE values meet the 10 CFR Part 50, Appendix G, USE requirement at the end of the period of extended operation (55 EFPY); therefore, the applicant's USE analyses are acceptable.

4.2.2.3 UFSAR Supplement

The applicant provided an UFSAR supplement summary description of its TLAA evaluation of the USE values for RPV materials in LRA Section A.2.4.1.2. On the basis of its review of the UFSAR supplement and consistent with SRP-LR Section 4.2.3.1.1.2, the staff concludes that the summary description of the applicant's actions to address USE is adequate.

4.2.2.4 Conclusion

On the basis of its review, consistent with SRP-LR Section 4.2.3.1.1.2, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the USE analyses have been projected to the end of the period of extended operation and will meet the criteria defined in Appendix G to 10 CFR Part 50. 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).

4.2.3 Pressurized Thermal Shock Analyses

4.2.3.1 Summary of Technical Information in the Application

LRA Section 4.2.3 summarizes the PTS evaluation of the Seabrook RPV beltline and extended beltline materials for the period of extended operation against the screening criteria established in accordance with the PTS rule 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." The applicant dispositions this TLAA in accordance with 10 CFR 54.21(c)(1)(ii).

For Seabrook, the applicant states that the limiting PTS reference temperature (RT_{PTS}) for plate and axial weld material is found for the Lower Shell Plate R1808-1 with an RT_{PTS} value after 55 EFPY of 123.3 degrees Fahrenheit (°F). The limiting RT_{PTS} value for Seabrook circumferentially-oriented welds at 55 EFPY is 8 °F, which corresponds to the intermediate-to-lower shell circumferential weld seam (101-171). The applicant concludes that each material in the Seabrook RPV that has a surface fluence value exceeding $1.0x10^{17}$ n/cm^2 (E > 1.0 MeV) at

55 EFPY has been demonstrated to have an RT_{PTS} value less than the applicable screening criterion; therefore, the RT_{PTS} value analyses have been satisfactorily projected for 60 years of operation.

4.2.3.2 Staff Evaluation

The staff reviewed LRA Section 4.2.3 to verify that the PTS analyses have been projected to the end of the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(ii) and consistent with SRP-LR Section 4.2.2.1.2.2.

Per the requirements of 10 CFR 50.61 (the PTS rule), license holders shall have projected RT_{PTS} values for each RPV beltline material through the end of their operating license. The RT_{PTS} value for each beltline material is evaluated from the following equation:

$RT_{PTS} = RT_{NDT(u)} + \Delta RT_{PTS} + M$

In this equation, $RT_{NDT(u)}$ is the unirradiated $RT_{NDT,}$ as defined in the ASME Boiler and Pressure Vessel Code, Section III, Paragraph NB-2331. ΔRT_{NDT} is the shift in RT_{NDT} caused by neutron irradiation, and M is the margin term to account for uncertainties in the calculation. The methodology used for determining ΔRT_{PTS} and the margin term M are described in the PTS rule, including provisions for the use of surveillance data. The PTS rule also provides the NRC-approved screening criteria for plates, forging, and axial weld materials (270 °F), and for circumferential weld materials (300 °F).

In LRA Table 4.2.3-1, the applicant presented the RT_{PTS} values after 55 EFPY for Seabrook. Also presented in these tables are the input parameters necessary for calculating the RT_{PTS} values.

For the RPV beltline materials, the staff performed its evaluation using the NRC's Reactor Vessel Integrity Database (RVID). The staff found that the Cu and nickel (Ni) contents and unirradiated RT_{NDT} for Seabrook RPV beltline materials in LRA Table 4.2.3-1 are almost identical to those in the RVID. The discrepancies did not significantly impact the RT_{PTS} evaluations for the subject welds. However, because RVID does not contain information for the extended beltline materials, the staff requested (part of RAI 4.2.2-1) that the applicant describe the procedures used to determine the chemistry data, initial RT_{NDT}, and margins for the extended beltline materials to demonstrate that they have applied consistent approaches for both the beltline and the extended beltline materials.

The applicant's February 3, 2011, response provided additional information from CMTRs, OEM certified letter reports, and the Seabrook UFSAR supporting the chemistry and unirradiated RT_{NDT} values in LRA Table 4.2.3-1. The staff considers these sources of the information for the extended beltline materials to be similar to those that are used for the beltline materials. Hence, consistent approaches have been used to determine the material information for both beltline and extended beltline materials, and the section of RAI 4.2.2-1 related to RT_{PTS} projections is resolved.

In summary, the staff performed a PTS evaluation for each of the extended beltline materials in Table 4.2.3-1. In all cases, the applicant's projected RT_{PTS} values from Table 4.2.3-1 were equal or more than that calculated by the staff, which confirms the validity (conservative nature) of the applicant's evaluation. The staff's analysis agrees with the applicant's projected RT_{PTS} value of 123.3 °F for the limiting material for Seabrook (lower shell R1808-1).

Based on the above discussion the staff concludes that all Seabrook RPV beltline and extended beltline materials satisfy the PTS requirements of 10 CFR 50.61 through the period of extended operation. The applicant's TLAA is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the Seabrook RPV materials have adequate RT_{PTS} values and fracture toughness through the period of extended operation.

4.2.3.3 UFSAR Supplement

The applicant provided an UFSAR supplement summary description of its TLAA evaluation of PTS in LRA Section A.2.4.1.3. On the basis of its review of the UFSAR supplement and consistent with SRP-LR Section 4.2.3.1.2.2, the staff concludes that the summary description of the applicant's actions to address PTS is adequate.

4.2.3.4 Conclusion

On the basis of its review and consistent with SRP-LR Section 4.2.3.1.2.2, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the PTS analyses have been projected to the end of the period of extended operation and will continue to meet the requirements of the PTS rule (10 CFR 50.61). 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).

4.2.4 Reactor Vessel Pressure-Temperature Limit and Low-Temperature Overpressure Protection Analyses

4.2.4.1 Summary of Technical Information in the Application

LRA Section 4.2.4 summarizes the evaluation of the RPV pressure-temperature (P-T) limit and low-temperature overpressure protection (LTOP_ analyses (collectively referred to as the P-T limit analyses) for the period of extended operation. The applicant developed the adjusted reference temperature (ART) values based on the material properties in LRA Table 4.2.3-1 and the ¼ and ¾ RPV wall thickness (¼T and ¾T) fluences for 55 EFPY. The resulting ART values for the limiting RPV materials at Seabrook were summarized in LRA Table 4.2.4-1 and were used to develop the P-T limits in accordance with the requirements of 10 CFR Part 50, Appendix G and Appendix G to Section XI of the ASME Code. Specifically, the LRA states that the Seabrook P-T limit curves for normal heatup and cooldown were developed using the 1995 Edition through the 1996 Addenda of the ASME Code, Section XI, Appendix G methodology and ASME Code Case N-641, "Alternative Pressure-Temperature Relationship and Low Temperature Overpressure Protection System Requirements."

The LRA states that the P-T limits analyses have been projected to the end of the period of extended operation; however, they will not be submitted with the LRA. The LRA concludes that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The application describes how the Reactor Vessel Surveillance Program (LRA B.2.1.19) monitors RPV embrittlement and provides data to update the P-T limits and, therefore, permits Seabrook to manage the P-T limits going forward, in accordance with 10 CFR 54(c)(1)(iii). The LRA states that the applicant will submit updates to the P-T limits for Seabrook to the NRC at the appropriate time to comply with 10 CFR Part 50, Appendix G.

4.2.4.2 Staff Evaluation

The staff reviewed LRA Section 4.2.4 to verify that the effects of aging on the P-T limits will be adequately managed by the applicant for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(iii) and consistent with SRP-LR Section 4.2.2.1.3.3.

LRA Section 4.2.4 states that updated P-T limits for the period of extended operation have been projected to the end of the period of extended operation; however, the applicant did not update the P-T limits in the LRA. The staff does not require the updated P-T limit curves for the period of extended operation to be submitted as part of this TLAA in the applicant's LRA. Prior to the expiration of the facility's current P-T limit curves, the applicant is required to submit revised P-T limits in accordance with 10 CFR Part 50, Appendix G, considering the increase of the limiting ART and plant-specific embrittlement information from additional surveillance data provided by the Reactor Vessel Surveillance Program.

As a part of a separate licensing action on P-T limits submitted by letter dated November 17, 2011, the applicant requested approval of P-T limits that would, based on an updated neutron fluence evaluation, extend the operating time of the current curves from 20 EFPY to 23.7 EFPY. The actual P-T limits and cold overprotection system setpoint curves do not change in the license amendment request (LAR).

During its review of the LAR, the staff,requested by letter dated April 25, 2012, that the applicant provide additional information related to whether the methodology used to develop the P-T limits is consistent with the requirements in 10 CFR 50, Appendix G. Because the methodology used to develop the P-T limits during the initial operating period is the same as that to be used during the period of extended operation, this additional information is also pertinent to the review of the LRA. Until the LAR questions are resolved, this item is identified as Open Item 4.2.4-1.

4.2.4.3 UFSAR Supplement

The applicant provided an UFSAR supplement summary description of its TLAA evaluation of P-T limits in LRA Section A.2.4.1.4. On the basis of its review of the UFSAR supplement, consistent with SRP-LR Section 4.2.3.1.3.3 and pending resolution of Open Item 4.2.4-1, the staff concludes that the summary description of the applicant's actions to address P-T limits is adequate.

4.2.4.4 Conclusion

On the basis of its review, pending resolution of Open Item 4.2.4-1, and consistent with SRP-LR Section 4.2.3.1.3.3, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the the P-T limits will be adequately managed by the applicant 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).

4.3 Metal Fatigue Analysis of Piping and Components

LRA Section 4.3 provides the assessment of the metal fatigue analyses for the applicant's pressure boundary components, including the RPV, RCPs, steam generators, pressurizer, piping, valves, and components of primary, secondary, auxiliary, steam, and other systems. The applicant considered these metal fatigue analyses as TLAAs for license renewal. The applicant stated that its nuclear steam supply system (NSSS) components are designed to ASME Code Section III, Class 1 rules (1971 Edition with addenda through summer 1972).

The applicant further stated that the fatigue evaluations discussed in LRA Section 4.3 can be classified into the following categories:

- explicit fatigue analyses for NSSS pressure vessel (i.e., the RPV) and components prepared in accordance with ASME Code Section III, Class A or Class 1 rules, developed as part of the original design
- supplemental explicit fatigue analyses for piping and components that were prepared in accordance with ASME Code Section III rules to evaluate transients that were identified after the original design analyses were completed
- new fatigue analyses (also in accordance with ASME Code Section III, Class 1 rules) prepared for license renewal to evaluate the effects of the reactor water environment on the sample of high fatigue locations applicable to newer vintage Westinghouse plants

4.3.1 Nuclear Steam Supply System Pressure Vessel and Component Fatigue Analyses (RPV and RPV Component Fatigue Analyses)

4.3.1.1 Summary of Technical Information in the Application

LRA Section 4.3.1 describes the applicant's TLAA for RPV and RPV component fatigue analyses. The applicant stated that the most limiting numbers of transients used in these NSSS component analyses are provided in LRA Table 4.3.1-2 and are considered design limits.

The applicant further stated that, since each Class 1 fatigue analysis is based upon the 40-year assumption for a set of design transients, these fatigue analyses have been identified as TLAAs that require evaluation for 60 years of plant operations. To determine if the fatigue analyses would remain valid for 60 years of service, a review of fatigue monitoring data was performed to determine the number of cumulative cycles for each transient that has occurred during past plant operations. For each transient, the applicant determined the average rate of occurrence based on past operation and then projected the number of future cycles using this average rate of occurrence. The applicant stated that the 60-year projection, provided in LRA Table 4.3.1-3, was determined by adding the cumulative number of occurrences as of April 1, 2009, and the projected number of future cycles. The applicant also stated that the methodology used to determine the 60-year projection is considered to produce a conservative estimate due to the declining trend of most of the transients since the beginning of plant operation. The applicant stated that the 40-year design transients bound the numbers of cycles projected to occur during 60 years of plant operations. The applicant dispositioned the RPV and RPV component fatigue TLAAs in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.3.1.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1 and the RPV and RPV components including Class 1 valves fatigue analyses TLAAs to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with SRP-LR Section 4.3.3.1.1.1. This SRP section requires that the staff review include the operating transient experience and a list of the assumed transients used in the existing cumulative usage factor (CUF) calculations for the current operating term to ensure that the number of assumed transients would not be exceeded during the period of extended operation.

LRA Table 4.3.1-2 lists the most limiting numbers of transients that are used in the RPV and RPV component fatigue analyses and are considered the design limits. The staff confirmed that these transients are consistent with those listed in UFSAR Table 3.9(N)-1; however, LRA Table 4.3.1-2 lists more design transients than those identified in TS 5.7 and TS Table 5.7-1. It was not clear to the staff if the design fatigue analyses for the RPV and its components were based on the design transients in TS Table 5.7-1 or the non-TS transients that were included in LRA Table 4.3.1-2 and UFSAR Table 3.9(N)-1. The staff also noted that the transients were termed differently between the LRA, UFSAR, and applicant's program basis documents. In addition, the UFSAR and the applicant's program basis documents for the Metal Fatigue of Reactor Coolant Pressure Boundary Program include auxiliary transients such as "charging and letdown flow shutoff and return" or "letdown flow step decrease and return," which are not in LRA Table 4.3.1-2.

As described in SER Section 3.0.3.2.21, the staff issued RAIs B.2.3.1-1 and B.2.3.1-2 by letter dated December 14, 2010, asking the applicant to clarify if the fatigue analyses were based on transients from TS Table 5.7-1 or LRA Table 4.3.1-2 and to confirm that the plant-specific cycle counting procedure tracks and monitors the transients listed in LRA Table 4.3.1-2. The staff also asked the applicant to clarify and justify the difference of designations for the transients and to clarify the significance of the auxiliary transients used in fatigue CUF analyses. The staff's evaluation of the applicant's responses to these RAIs is documented in SER Section 3.0.3.2.21. The staff found the applicant's design transient cycle counting basis, as amended in response to RAI B.2.3.1-1, acceptable because the applicant provided an adequate explanation that the CUF analyses were based on the transients in LRA Table 4.3.2-1 and not only those transients in TS Table 5.7-1. Further, the applicant amended LRA Table 4.3.1-2 to provide an updated list of all transients that will be monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program during the period of extended operation. The staff also found the applicant's design transient cycle counting basis, as amended in responses to RAI B.2.3.1-2, acceptable because the applicant did the following:

- provided an adequate explanation for the difference in the transient designations and categories that were listed in LRA Table 4.3.1-2
- provided an adequate summary on how the Metal Fatigue of RCPB would track and monitor the number of transients occurring at the facility
- provided an adequate explanation of the significance of those auxiliary system transients that were analyzed for in the fatigue calculations

LRA Section 4.3.1 discusses the 60-year transient projection methodology that was determined by adding the cumulative number of occurrences as of April 1, 2009, to the number of cycles predicted to occur in the 41 years of future operation. The staff noted that the 60-year projected cycles for the "Unit Loading Between 0% and 15% Power" and "Unit Unloading Between 0% and 15% Power" transients in LRA Table 4.3.1-3 are not consistent with the current count for these transients. In particular, the projected numbers (listed as 13 and 10) are less than the actual counts as of April 1, 2009, (listed as 27 and 26) for the "Unit Loading Between 0% and 15% Power" and "Unit Unloading Between 15% and 0% Power" transients, respectively.

By letter dated January 5, 2011, the staff issued RAI 4.3.1-1 asking the applicant to justify why the values of 60-year projected cycles are less than the values of the "Current Cycles" for these two transients.

In its response dated February 3, 2011, the applicant acknowledged that LRA Table 4.3.1-3 incorrectly reflects the values of 60-year projected cycles as less than the values of current cycles for "Unit Loading and Unloading Between 0% and 15% Power" transients. The applicant stated that the current cycle counts and the 60-year projection "Unit Loading Between 0% and 15% Power" should be 27 and 70, respectively. The applicant also indicated that the current cycle counts and the 60-year projection for "Unit Unloading Between 15% and 0% Power" should be 26 and 65, respectively.

LRA Section 4.3.1 states that the 60-year cycle projection for the "the transients were linearly extrapolated based on the rate of accumulation for the data available through April 1, 2009. Based on its review, the staff found that the applicant's response was unacceptable because the revised values for the 60-year projected cycles for the two transients were not linearly extrapolated based on the rate of accumulation for the data available through April 1, 2009. The staff noted that, if these transients were linearly extrapolated, the resultant 60-year projected cycles would be approximately 87 and 83 cycles for the "Unit Loading Between 0% and 15% Power" and "Unit Unloading Between 15% and 0% Power" transients, respectively.

By letter dated March 30, 2011, the staff issued followup RAI 4.3.1-1b asking the applicant to provide the basis and justify the 60-year projected values for the unit loading and unit unloading transients. In its response dated April 22, 2011, the applicant stated that a revised manual count revealed that there have been 48 occurrences of each of the two events ("Unit Loading between 0% and 15% Power" and "Unit Unloading between 15% and 0% Power") between the start of plant operation in August of 1990 and October 2009 (18.6 years of full power operation). The applicant stated that, using a linear projection, the 60-year projected count of 155 is less than the design basis of 500 cycles. The staff noted that, in LRA Section 4.3.1, the applicant discussed that the linear extrapolation is conservative due to the declining trend of most of the transients since the beginning of plant operation.

Based on its review, the staff finds the applicant's response to RAI 4.3.1-1b acceptable because the applicant projected the occurrence of the two transients using a projection method that is consistent with that for other transients in the LRA and the projected counts of the two transients are less than the design basis for these transients. The staff's concern described in RAI 4.3.1-1b is resolved.

The staff noted that, in LRA Table 4.3.1-3, the number of NSSS design cycles for the feedwater heaters out of service transient is "120" with footnote (5), which indicates that the original design cycles is assumed to be the anticipated number of cycles at the end of the period of extended operation. However, the staff noted that the number of 60-year projected cycles, in LRA Table 4.3.1-3, for this transient is 39 cycles. The staff also noted that LRA Table 4.3.1-2 identifies three emergency transients that are RCS design transients. However, the applicant did not provide the number of current and 60-year projected cycles for these three emergency transients in LRA Table 4.3.1-3.

By letter dated March 30, 2011, the staff issued RAI 4.3.1-2 requesting the applicant to amend LRA Table 4.3.1-3 to reflect the proper 60-year projected cycles for the feedwater heaters out of service transient or justify why footnote (5) is not applicable to this transient. The staff also asked the applicant to provide the number of current and 60-year projected cycles for the three emergency transients in LRA Table 4.3.1-3 or justify why cycle projections are not needed.

Furthermore, the staff asked the applicant to clarify if these emergency transients will be monitored under the Metal Fatigue of Reactor Coolant Pressure Boundary Program or to justify why the transients are not monitored.

In its response dated April 22, 2011, the applicant stated that footnote (5) of LRA Table 4.3.1-3 is not applicable to the feedwater heaters out of service transient. The staff noted the 60-year projected cycle for this transient is consistent with other transient projections in LRA Table 4.3.1-3 and the removal of footnote (5) indicates that the transient will be counted in the Metal Fatigue of Reactor Coolant Pressure Boundary Program. In addition, the applicant stated that, for the feedwater cycling at hot shutdown transient, the current cycle count is 192 through April 1, 2010, and it is based on the assumption that there are four occurrences of feedwater cycling at hot shutdown per each “unit loading between 0% and 15% power” transient. The applicant stated that, using a linear projection, the 60-year projected count of 620 is less than the design basis of 2,000 cycles. The applicant explained that the linear extrapolation is conservative due to the declining trend of most of the transients since the beginning of plant operation.

The applicant also stated that the three emergency transients (small break loss-of-coolant accident (small break LOCA), small main steam line break, and complete loss of flow), identified in LRA Table 4.3.1-2, are not part of its fatigue design basis, and they are not included in the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The applicant stated that these three emergency transients have not occurred to date and are not expected to occur during the life of the plant. Thus, the applicant stated that the 60-year projected number of cycles for each of them is one. The staff noted that the applicant’s 60-year projection of one occurrence for each of the three transients is consistent with the projection, in LRA Section 4.3.1, for other transients that have not occurred. Based on its review, the staff finds the applicant’s response to RAI 4.3.1-2 acceptable for the following reasons:

- The applicant revised and justified the feedwater cycling at hot shutdown transient current cycle count and 60 year projection; and
- The applicant clarified that certain transients have been appropriately included in the cycle projection to support its TLAA disposition basis.

The staff’s concern described in RAI 4.3.1-2 is resolved.

The staff finds the use of this linear extrapolation conservative because the applicant considered the time period when it experienced frequent transient occurrences in its extrapolation and did not only consider its recent improved operating history.

The staff noted that LRA did not provide the CUF values of record for the RPV and RPV components (LRA Section 4.3.1), the ASME Section III Class 1 piping and components (LRA Section 4.3.2), or the reactor vessel internals (RVIs) (LRA Section 4.3.3). Without these values, the staff could not ascertain whether the CUF for any location exceeded the allowable limit or evaluate the applicant’s dispositions for these TLAAs in accordance with 10 CFR 54.21(c). Furthermore, the staff noted that UFSAR Table 3.9(B)-21 provides a CUF value of 0.95 for the ASME Section III Class 1 piping of the RCS pressurizer safety and relief valve system. LRA Table 3.1.2-1 indicates that, for the component “Valve Body (Class 1),” a TLAA is used to manage cumulative fatigue damage; however, LRA Section 4.3 did not provide the details of a fatigue analysis for ASME Code Class 1 valves. It was not clear to the staff how the metal fatigue TLAA of all Class 1 valves were dispositioned in accordance with 10 CFR 54.21(c).

By letter dated January 5, 2011, the staff issued RAI 4.3-1 asking the applicant to do the following:

- provide the original design basis 40 year CUF values and projected 60 year CUF values for all components or critical locations or both that are applicable to the dispositions in LRA Sections 4.3.1, 4.3.2, and 4.3.3
- clarify and justify the disposition of all Class 1 valves metal fatigue analyses that are TLAAs in accordance with 10 CFR 54.21(c)

In its response dated February 3, 2011, the applicant provided the original design basis 40-year CUF values for all components that are applicable to the dispositions in LRA Sections 4.3.1, 4.3.2, and 4.3.3. The applicant stated that, since the original 40-year design-basis number of transient cycles will not be exceeded during the period of extended operation, the fatigue analyses for these components will be dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

Based on its review, the staff finds the applicant's response to this portion of RAI 4.3-1 acceptable because the staff confirmed that the projected CUF values will not exceed the allowable limit of 1.0, which supports the applicant's TLAA disposition basis.

The applicant also stated, in its response to RAI 4.3-1, that fatigue conformance of ASME Class 1 valves was demonstrated by performing an "umbrella" fatigue analysis of the piping system which contains the valves, in accordance with ASME Section III, Subsection NB-3650. The applicant stated that, for all transient loading combinations, allowable moment ranges were developed so that the requirements of Subsection NB-3650 are met and fatigue conformance of the analyzed valves was demonstrated when CUF value of the umbrella fatigue analysis is less than 1.0. The applicant stated that design-basis plant transients listed in LRA Table 4.3.1-2 were considered in these "umbrella" fatigue analyses in terms of severity and number of occurrences. The applicant also indicated that the "umbrella" fatigue analyses is dispositioned in accordance with 10 CFR 54.21(c)(1)(i) because the design-basis number of the occurrences of the transients will not be exceeded during the 60-year period.

During its review, the staff noted that UFSAR Section 3.9(N).1.4(e), "Analysis of Primary Component," states that the pressure boundary portions of Class 1 valves in the RCS were designed and analyzed according to the requirements of ASME Code Section III, NB-3500 (1971 Edition including 1972 Addenda). It was not clear to the staff why a fatigue evaluation of Class 1 valves was performed in accordance with ASME Code Section III Subsection NB-3650, "Analysis of Piping Products," instead of the design requirements of Subsection NB-3500 as indicated in UFSAR Section 3.9(N).1.4(e). Furthermore, the applicant did not provide adequate information for the staff to verify whether the "umbrella" NB-3650 analysis is equivalent or more conservative than a NB-3500 analysis.

By letter dated March 30, 2011, the staff issued followup RAI 4.3-1b asking the applicant to clarify and explain why Class 1 valve fatigue conformance was demonstrated by an "umbrella" fatigue analysis using ASME Code Section III Subsection NB-3650 instead of Subsection NB-3500. In addition, the staff asked the applicant to justify that the "umbrella" fatigue analysis using Subsection NB-3650 is equivalent to or more conservative than an analysis in accordance with NB-3500.

In its response to RAI 4.3-1b dated April 22, 2011, the applicant clarified that the ASME Class 1 valves in the RCS were designed, analyzed, and qualified for service in accordance with the rules of ASME Section III Subsection NB-3500, as stated in the UFSAR Section 3.9(N).1.4(e).

The applicant explained that the piping design rules from ASME Section III Subsection NB-3650 were used to analyze and qualify the piping system, including piping components such as installed Class 1 valves. The applicant noted that part of this piping analysis is an umbrella fatigue analysis that was discussed in its response to RAI 4.3-1 dated February 3, 2011.

However, the staff noted that the 1971 and later editions of the ASME Code Section III required fatigue analyses for valves with an inlet piping connection larger than 4 inches (in.) nominal pipe size unless exemption requirements were met. It was not clear to the staff if the fatigue analyses for all Class 1 valves performed in accordance with the requirements of the applicable ASME codes have been dispositioned in accordance with 10 CFR 54.21(c)(1). By letter dated October 7, 2011, the staff issued followup RAI 4.3-1c asking the applicant to provide and justify the TLAA disposition for fatigue analysis that were performed for Class 1 valves or justify that the fatigue analyses for these Class 1 valves need not to be identified as a TLAA in accordance with 10 CFR 54.3.

In its response to RAI 4.3-1c dated November 2, 2011, the applicant stated that a fatigue analysis was performed for Class 1 valves that have an inlet piping connection larger than 4 in. nominal pipe size as part of the original design in accordance with ASME Code Section III Subsection NB-3500. The applicant stated that the 40-year design numbers of transient occurrences that are used in the Class 1 valves fatigue analysis bound the number of cycles projected to occur during 60 years of plant operations. Therefore, the applicant concluded the fatigue analysis that was based upon the 40-year design transients remain valid for the period of extended operation and the TLAA is dispositioned, along with the fatigue analyses of NSSS components, in accordance with 10 CFR 54.21(c)(1)(i). The applicant also revised LRA Section 4.3.1 specifying that TLAA for Class 1 valves and piping are also included. The staff noted that the 60-year projections for the design transients are included in LRA Table 4.3.1-3.

Based on its review, the staff finds the applicant's response to RAI 4.3-1c acceptable because the applicant dispositioned the Class 1 valves fatigue TLAA in accordance with 10 CFR54.21(c)(1), and the number of assumed design transients in the Class 1 valves fatigue analysis would not be exceeded by the projected number of cycles during the period of extended operation. The staff's concern described in RAI 4.3-1c is resolved.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the RPV and RPV components, including Class 1 valves fatigue analyses, remain valid for the period of extended operation. Additionally, the analyses meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.1, because the number of assumed design transients would not be exceeded during the period of extended operation.

4.3.1.3 UFSAR Supplement

LRA Section A.2.4.2.1 provides the UFSAR supplement summarizing RPV and RPV components including Class 1 valves fatigue analyses. The staff reviewed LRA Section A.2.4.2.1 consistent with SRP-LR Section 4.3.3.3, which states that the summary description should contain information associated with the evaluation of the RPV and RPV component including Class 1 valves fatigue analyses.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP LR Section 4.3.2.3. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address the RPV and RPV components including Class 1 valves fatigue analyses, as required by 10 CFR 54.21(d).

4.3.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the fatigue analyses for the RPV and RPV components, including Class 1 valves, will 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).

4.3.2 Supplementary ASME Section III, Class 1 Piping and Component Fatigue Analysis

LRA Subsection 4.3.2 provides a summary of the applicant's fatigue analysis for components affected by the considerations in NRC Bulletins 88-08 and 88-11. The applicant divided the summary into the following subsections:

- NRC Bulletin 88-08: Absence of a TLAA for Thermal Stresses in Piping Connected to Reactor Coolant Systems
- NRC Bulletin 88-11: Pressurizer Surge Line Thermal Stratification

Both fatigue analyses address modified or additional transients postulated in response to the NRC Bulletins for these ASME Section III Class 1 components, in addition to the original design basis transients. LRA Subsection 4.3.2 states that these piping and components were originally designed in accordance with the ASME Section III, 1971 Edition including addenda through winter 1972. In addition, the related fatigue analyses were updated to address the potential valve leakage transients, identified in NRC Bulletin 88-08, for the auxiliary spray line, charging lines, and safety injection lines. These analyses were also updated to address the thermal stratification transient in pressurizer surge line (PSL), identified in NRC Bulletin 88-11. The applicant also stated that both the original and updated analyses do not account for environmental effects and either the design cycles or the projected cycles (based on actual service cycle counts) enveloped the 60 years of operation.

4.3.2.1 Absence of a TLAA for Thermal Stresses in Piping Connected to RCSs: NRC Bulletin 88-08

4.3.2.1.1 Summary of Technical Information in the Application

LRA Section 4.3.2.1 describes the applicant's evaluation for the absence of a TLAA for thermal stresses in piping connected to the RCS. The applicant stated that, in response to NRC Bulletin 88-08, it evaluated the possibility and effects of fluid in-leakage to the RCS from leaking valves by identifying seven piping sections that are unisolable from the RCS and pressurized by the charging pumps. The applicable plant-specific locations are four high head safety injection lines and three charging system lines. The applicant also stated that, in 1988, prior to initial criticality, a one-time non-destructive examination was performed for the four high head safety injection lines, and the examination showed acceptable results. In addition, in 1989, prior to initial criticality, the applicant deployed a temperature monitoring program for the high head safety injection lines and three charging system lines. The LRA stated that this monitoring is still installed and credited in its Management of Thermal Fatigue Program for Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines (MRP-146/146S).

The applicant further stated that it evaluated the possibility of and the effects from fluid out-leakage and concluded that unisolable piping sections connected to the RCS are not subject to stresses from thermal stratification or temperature oscillations resulting from the mechanism described in NRC Bulletin 88-08 and related supplements. The LRA also states that the NRC approved Seabrook Station's response to NRC Bulletin 88-08. Therefore, the applicant stated that there is no specific TLAA for locations addressed by NRC Bulletin 88-08 and related supplements.

4.3.2.1.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.1 and the applicant's evaluation for the absence of a TLAA for thermal stresses in piping connected to the RCS to verify, consistent with SRP-LR Section 4.1.3, the applicant's basis for concluding that there is no specific TLAA associated with the mechanisms described in NRC Bulletin 88-08 and related supplements.

LRA Section 4.3.2.1 states that unisolable piping sections connected to the RCS are not subject to stresses from thermal stratification or temperature oscillations resulting from the mechanism described in NRC Bulletin 88-08. The applicant stated that, in the charging system, the temperature differences imposed upon the unisolable piping sections during normal operation are limited to acceptable values because any leakage would first pass through the regenerative heat exchanger and become sufficiently heated. The applicant further stated that it deployed a temperature monitoring program that detects adverse temperature distributions and has established appropriate temperature limits. The staff confirmed the deployment of the temperature monitoring program in applicant's response to Bulletin 88-08, dated Jan 13, 1989, The staff found that the temperature monitoring program was acceptable to provide continuing assurance that unisolable sections of all piping connected to the RCS will not be subjected to combined cyclic and static thermal and other stresses that could cause fatigue failure during the remaining life of the unit. The applicant stated that the monitoring is still installed and credited its own Management of Thermal FatigueProgram for Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines under MRP-146/146S. The staff noted that the aging effect of craking is managed by that the applicant's One-Time Inspection of ASME Code Class 1 Small Bore Piping program, which credited the inspection and monitoring recommendations in MRP-146/146S. The staff's review of the applicant's One-Time Inspection of ASME Code Class 1 Small Bore Piping program is doucmented in SER Section 3.0.3.2.13.The staff finds the applicant's conclusion, that there is no specific TLAA associated with NRC Bulletin 88-08, acceptable because the applicant has demonstrated that its CLB does not contain an analysis that considers cumulative fatigue damage associated with NRC Bulletin 88-08; therefore, it is not a TLAA, in accordance with Criteria 2 and 6 of 10 CFR 54.3(a).

4.3.2.1.3 UFSAR Supplement

On the basis of its review, the staff finds that a UFSAR supplement is not required because a TLAA associated with thermal stresses in piping connected to the RCS and NRC Bulletin 88-08 is not applicable, as described above.

4.3.2.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant demonstrated that the CLB does not contain an analysis that considers cumulative fatigue damage associated with NRC Bulletin 88-08; therefore, it is not a TLAA. The staff also concludes that a UFSAR supplement is not required.

4.3.2.2 NRC Bulletin 88-11, PSL Thermal Stratification

4.3.2.2.1 Summary of Technical Information in the Application

LRA Section 4.3.2.2 provides the applicant's evaluation of the TLAA for the PSL, pressurizer surge nozzle (PSN), and hot leg surge line nozzle (HLSN) subject to thermal stratification and striping in addition to the original design transients. The applicant stated that thermal stratification was not part of the original piping design, but it was later identified by industry operating experience that resulted in issuance of NRC Bulletin 88-11. The applicant also stated that it previously evaluated the PSL piping and nozzles for the effects of thermal stratification and identified the HLSN as the limiting fatigue location. The applicant further stated that it performed the ASME Section III, Class 1, fatigue analysis for both the PSN and the HLSN locations for the plant-specific modified transients, based on the NSSS vendor evaluation of its operating procedures.

The applicant dispositioned the "NRC Bulletin 88-11, Pressurizer Surge Line Thermal Stratification," related ASME Section III, Class 1, fatigue TLAAs (without environmental effects) for the PSL, PSN, and HSLN, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.3.2.2.2 Staff Evaluation

The staff reviewed LRA Subsection 4.3.2.2 and the ASME Section III, Class 1, fatigue TLAAs for PSL thermal stratification to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation. The staff reviewed these TLAAs and the corresponding disposition by the applicant, consistent with SRP-LR Section 4.3.3.1.1.1, which states that the operating transient experience and the list of assumed transients in the existing CUF calculations for the current operating term should be reviewed to ensure that the number of assumed transients would not be exceeded by the number of transient cycles projected to occur at the end of the period of extended operation.

LRA Section 4.3.2.2 states that the PSL piping was previously evaluated for the effects of thermal stratification and plant-specific transients in 1990, and it was determined that the PSL will remain within the ASME Code requirements for the design life. However, the applicant did not provide the details of this analysis; therefore, the staff was not able to verify the applicability of thermal stratification during the period of extended operation. LRA Section 4.3.2.2 also states that the evaluation of the structural weld overlay applied to the PSN includes an elastic-plastic formulation and resulted in a CUF value less than 1.0. The staff was not able to verify acceptability of the elastic-plastic analyses. By letter dated January 5, 2011, the staff issued RAI 4.3.2-1 requesting that the applicant provide the CUF values in the original design and updated analyses for 60-year operation, without environmental effects, for all components that are applicable to LRA Section 4.3.2.2. The staff also asked the applicant to clarify how the elastic-plastic formulation was used in the evaluation to reduce the conservatism that existed in the evaluations prior to the structural weld overlay. Furthermore, the staff asked the applicant to justify how the disposition of 10 CFR 54.21(c)(1)(i) is appropriate for these components.

In its response to RAI 4.3.2-1 dated February 3, 2011, the applicant provided CUF values for the PSL, PSN, and HLSN components from the original design basis analyses, the subsequent analyses performed for power uprate, weld overlay repair activity, and in support of license renewal. The staff noted that the 60-year CUF values in the subsequent analysis in support of license renewal are less the limit of 1.0.

In its response to RAI 4.3.2-1 Requests 2 and 3, the applicant also clarified that the PSN weld-overlay repair was reanalyzed with a non-linear elastic-plastic method to determine the refined CUF. The applicant stated that the maximum CUF is 0.6325, and the analysis showed that shakedown occurred within 10 cycles (e.g., deformation does not continue after 10 cycles). The applicant also stated that transients in the design analyses and updated analyses for the PSL, PSN, and HLSN were developed based on the transients listed in LRA Table 4.3.1-2, and the occurrences of the thermal stratification transients were correlated to the RCS heatup and RCS cooldown transients. The staff noted that for all the transients in LRA Table 4.3.1-2, including RCS heatup and RCS cooldown, the current cycle count and the 60-year projections are bounded by NSSS design limits.

Based on its review, the staff finds the applicant's response to RAI 4.3.2-1 acceptable because (1) the CUF values for the PSL, PSN, and HLSN are less than 1.0; (2) the applicant demonstrated that the reduction in excess conservatism was appropriate in accordance with ASME Code Section III, Subsection NB-3228, on plastic analysis, which permits the relaxation of stress limits provided that shakedown is confirmed by the analysis; and (3) the applicant supported the 10 CFR 54.21(c)(1)(i) disposition of the TLAA by indicating that all applicable transients, including the thermal stratification transients, are included in LRA Table 4.3.1-2, and the 60-year projections of all the transients are bounded by NSSS design limits. The staff's concern described in RAI 4.3.2-1 Requests 2 and 3 are resolved.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the fatigue analyses for PSL thermal stratification remain valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.1 because the 60-year projected number of cycles of the transients in the design analyses and the updated analyses will not exceed the NSSS design limits during the period of extended operation, and thus the bounding CUF values for these components are all less than the design limit of 1.0.

4.3.2.2.3 UFSAR Supplement

LRA Section A.2.4.2.2.1 provides the UFSAR supplement summarizing the ASME Section III, Class 1, fatigue TLAAs for PSL thermal stratification, which address the additional transients from thermal stratification identified in NRC Bulletin 88-11. The staff reviewed LRA Subsection A.2.4.2.2.1, consistent with SRP-LR Section 4.3.3.3, which states that the summary description should contain information associated with the TLAA for PSL thermal stratification regarding the basis for determining that the applicant has made the demonstration required by 10 CFR 54.21(c)(1).

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.3. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address PSL thermal stratification, as required by 10 CFR 54.21(d).

4.3.2.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the fatigue analyses for the PSL thermal stratification (identified in NRC Bulletin 88-11) 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).

4.3.3 Reactor Vessel Internals Aging Management

4.3.3.1 Summary of Technical Information in the Application

LRA Section 4.3.3 describes the applicant's TLAAs for its RVIs. The applicant stated that, in order to assure continued functionality of the RVIs during the desired operating period, including license renewal, it is essential to demonstrate that the effects of aging are adequately managed.

In addition to metal fatigue, LRA Section 4.3.3 identifies several other aging mechanisms for the RVIs, including stress corrosion cracking (SCC); irradiation-assisted SCC; wear; thermal aging embrittlement; irradiation embrittlement; void swelling and irradiation growth; and, thermal and irradiation-enhanced stress relaxation or irradiation-enhanced creep. LRA Section 4.3.3 states that the EPRI Materials Reliability Program (MRP) Reactor Internals Inspection and Evaluation (I&E) Guidelines, MRP-227, are intended to support a demonstration that the effects of aging on the RVI are adequately managed during the plant operating period, including license renewal. This LRA section further states that the PWR Vessel Internals Program will manage the aging effects for the RVI components.

LRA Section 4.3.3 dispositions the TLAAs for the RVIs in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation by the PWR Vessel Internals Program.

4.3.3.2 Staff Evaluation

The staff reviewed LRA Section 4.3.3 and the TLAAs for the RVIs to verify, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of cumulative fatigue damage; stress corrosion cracking (SCC); irradiation-assisted SCC; wear; thermal aging embrittlement; irradiation embrittlement; void swelling and irradiation growth; and, thermal and irradiation-enhanced stress relaxation or irradiation-enhanced creep on the intended functions will be adequately managed for the period of extended operation.

The staff reviewed the applicant's TLAAs and the corresponding disposition, consistent with SRP-LR Section 4.3.3.1.1.3, which state that the reviewer should verify the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components. The SRP-LR further states that the reviewer should verify that the applicant has identified the appropriate program as described and evaluated in the GALL Report. Furthermore, the reviewer should also ensure that the applicant's program contains the same program elements that the staff evaluated and relied upon in approving the corresponding generic program in the GALL Report.

LRA Section 4.3.3 states that the applicant's RVIs were designed and constructed prior to the development of ASME Code requirements for core support structures, but the RCS functional design requirements were considered in the design. Furthermore, the RVIs were analyzed for fatigue as part of a power uprate, and it was determined that the 40-year CUFs would remain less than 1.0. However, the staff noted that the LRA and the UFSAR do not provide a list of CUF values for the RVI components. Without this information, the staff was unable to evaluate the applicant's disposition for these TLAAs. The staff noted during the aging management program (AMP) audit that the CUF for some RVIs, such as the upper and lower core plates or baffle-former bolts, could be greater than 0.5 and would require evaluation for the period of extended operation.

The staff also noted that LRA Section 4.3.3 states that the PWR Vessel Internals Program will manage changes in dimensions, cracking, loss of fracture toughness, wear, and loss of preload of the RVI components for the period of extended operation. The staff's evaluation of the applicant's PWR Vessel internals Program is documented in SER Section 3.0.3.3.5.

The staff noted that SRP-LR Section 4.3.2.1.1.3 provides the staff's recommendations for accepting CUF calculations in accordance with 10 CFR 54.21(c)(1)(iii). The staff noted that this SRP-LR section recommends that a program analogous or equivalent to GALL Report AMP X.M1, “Metal Fatigue of Reactor Coolant Pressure Boundary,” be credited as the AMP for accepting CUF-based TLAAs in accordance with 10 CFR 54.21(c)(1)(iii) and for managing cumulative fatigue damage on the component intended functions during the period of extended operation.

The staff noted that the applicant's proposed aging management methodology did not conform to the recommendations in SRP-LR Section 4.3.2.1.1.3 because the applicant credited its PWR Vessel Internals Program to manage cumulative fatigue damage of the RVI and their associated TLAAs. The staff noted that the applicant did not provide an acceptable basis for using the PWR Vessel Internals Program to disposition the RVI metal fatigue TLAAs in accordance with 10 CFR 54.21(c)(1)(iii) because the applicant did not provide sufficient information to support that the PWR Internals Program will adequately manage the effects of metal fatigue for the RVI components that have a CUF analysis.

By letter dated January 5, 2011, the staff issued RAI 4.3.3-1, asking the applicant to justify its basis for concluding that the proposed AMP would adequately manage cumulative fatigue damage for the RVI components during the period of extended operation. The staff also asked the applicant to provide, if appropriate, updated CUFs for the period of extended operation for the reactor internals and to justify the proposed TLAA dispositions in accordance with 10 CFR 54.21(c)(1)(i) or 10 CFR 54.21(c)(1)(ii).

In its response to RAI 4.3.3-1 dated February 3, 2011, the applicant stated that the intent is to disposition metal fatigue of the vessel internals using 10 CFR 54.21(c)(1)(i). The applicant also stated that in accordance with the ASME Code at the time of construction, CUF values were not calculated for the RVI components as part of the original design basis. The staff confirmed that CUF calculations for the RVI components were not required by the ASME Code and a TLAA disposition is not necessary. The applicant stated that plant-specific fatigue analyses for the limiting vessel internals locations were performed to support the stretch power uprate application for the facility, which was approved in an NRC safety evaluation dated February 28, 2005. The applicant stated that the power uprate basis identified the following plant limiting fatigue locations for metal fatigue analysis: lower support columns, core barrel nozzle, lower core plate, and upper core plate.

The applicant provided fatigue 40-year CUFs for these locations in its response to RAI 4.3.3-1, and the staff confirmed the CUF values for the limiting RVI component locations were all less than 1.0. The applicant further stated that the effects of fatigue on these specific locations would be monitored by cycle counting under its Metal Fatigue of Reactor Coolant Pressure Boundary Program during the period of extended operation to verify that the number of design cycles assumed in the analyses will not be exceeded. However, the applicant also stated that the “intent of the fatigue management program is to disposition fatigue of the vessel internals using 10 CFR 54.21 (c)(1)(i); that is, applying results of supplemental fatigue analyses to demonstrate continued acceptance of the components.” The staff noted that the acceptance criteria in SRP-LR Section 4.3.2.1.1.1 states that the metal fatigue CUF TLAAs may be accepted in accordance with 10 CFR 54.21(c)(1)(i) if it can be demonstrated that the “existing CUF calculations remain valid because the number of assumed transients would not be exceeded during the period of extended operation.” A CUF TLAA may not be dispositioned in accordance with 10 CFR 54.21(c)(1)(i) by crediting an AMP to manage the effects of cumulative fatigue damage on the component's intended functions during the period of extended operation. Therefore, the staff found the applicant's response to RAI 4.3.3-1 unacceptable because, the applicant did not demonstrate the number of transient cycles analyzed for in the existing CUF analyses would bound the number of corresponding transient cycles that would be projected to occur at the facility through 60 years of licensed operations.

By letter dated March 30, 2011, the staff issued RAI 4.3.3-1b, asking the applicant to revise LRA Section 4.3.3—and applicable sections in LRA Appendix A—to indicate that, for the specific RVI components, the TLAA disposition complies with 10 CFR 54.21(c)(1)(i) and 10 CFR 54.21(c)(1)(iii), using its Metal Fatigue of Reactor Coolant Pressure Boundary Program. In its response dated April 22, 2011, the applicant revised LRA Section 4.3.3 such that it is consistent with its response dated February 3, 2011. The applicant amended its discussion of metal fatigue in LRA Section 4.3.3, indicating that the effects of fatigue on these specific locations of the RVI will be monitored by cycle counting under its Fatigue Monitoring Program. However, the staff noted that there is no AMP called “Fatigue Monitoring Program” in the LRA. The applicant also revised the TLAA disposition basis to 10 CFR 54(c)(1)(i), that the Metal Fatigue of Reactor Coolant Pressure Boundary Program will monitor the number of design cycles assumed in the fatigue analysis to assure that these will not be exceeded. The staff noted that the appropriate TLAA disposition basis for using an AMP should be 10 CFR 54(c)(1)(iii). Furthermore, the staff noted that LRA Section A.2.4.2.2.2 was not updated to reflect the changes in LRA Section 4.3.3 due to the letter dated April 22, 2011.

By letter dated May 23, 2011, the staff issued RAI 4.3.3-1c, asking the applicant to revise LRA Section 4.3.3—and the applicable section in LRA Appendix A—to indicate that, for the specific locations of the RVI, the TLAA disposition is in accordance with 10 CFR 54.21(c)(1)(iii), using its Metal Fatigue of Reactor Coolant Pressure Boundary Program.

In its response dated June 2, 2011, the applicant revised LRA Section 4.3.3, the TLAA disposition basis, for the specific locations of the RVI, to 10 CFR 54(c)(1)(iii) to state that the Metal Fatigue of Reactor Coolant Pressure Boundary Program will monitor the number of design cycles assumed in the fatigue analysis to assure that these will not be exceeded. The applicant also updated LRA Section A.2.4.2.2.2 to reflect the TLAA disposition basis. The staff confirmed that the applicant’s Metal Fatigue of Reactor Coolant Pressure Boundary Program tracks the number of transient cycles that occur and this program also requires the applicant to take corrective actions prior to any analyzed number of cycles being reached in the applicable TLAA, which ensures that the analyses remain valid and the design limit of 1.0 is not exceeded. The staff’s evaluations of the applicant’s Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.21.

Based on its review, the staff found the applicant's response acceptable because the applicant provided an accurate TLAA disposition basis and consistent UFSAR supplement for the specific locations of the RVI by updating LRA Section 4.3.3 and Section A.2.4.2.2.2. The staff’s concern described in RAI 4.3.3-1c is resolved.

The staff also noted that LRA Table 3.1.2-3 indicates that a TLAA is credited for the flux thimble tubes and flux thimble guide tubes to manage cumulative fatigue damage. However, LRA Section 4.3.3 does not provide CUF values for the flux thimble tubes and flux thimble guide tubes to support this TLAA disposition. By letter dated January 5, 2011, the staff issued RAI 4.3.3-2, asking the applicant to provide the CUF values for the flux thimble tubes and flux thimble guide tubes and to ensure that cumulative fatigue damage of these components will be adequately managed by the PWR Vessel Internal Program, in accordance with 10 CFR 54.21(c)(1)(iii).

In its response dated February 3, 2011, the applicant stated that the flux thimble tubes are not within the scope of license renewal, and LRA Table 3.1.2-3 has been revised in response to RAI 3.1.1.60-2. The applicant stated that LRA Table 3.1.2-3 incorrectly listed cumulative fatigue damage as an aging effect requiring management for the flux thimble tubes and the line item will be deleted. The staff's evaluation of the applicant's response to RAI 3.1.1.60-2 is documented in SER Section 3.1.2.1.1. The applicant also stated that the flux thimble guide tubes are internal to the RPV for structural support of the flux thimble tubes and they do not have a fatigue analysis. Thus, a metal fatigue TLAA disposition is not necessary. The applicant also stated that the RPV bottom head instrument tubes are ASME Class 1 components, associated with the RPV, with a CUF value of 0.3184. The applicant explained that, as discussed in LRA Section 4.3.1, since the 40-year design transient cycle numbers bound the numbers of projected cycles during 60-years operation, the NSSS Class 1 fatigue analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). The staff also confirmed the Section III Subsection NC of the ASME Code, which consists of the stress requirements to which the flux thimble guide tubes were designed, does not require a fatigue evaluation.

Based on its review, the staff finds the applicant's response to RAI 4.3.3-2 acceptable because the flux thimble guide tubes are not required by the ASME Code to have a fatigue analysis Additionally, the applicant demonstrated that the metal fatigue TLAA disposition for the bottom head instrument tubes is in accordance with 10 CFR 54.21(c)(1)(i). The staff's concern described in RAI 4.3.3-2 is resolved.

LRA Table 4.1-2 states that the analysis associated with flow-induced vibration (FIV) endurance limit is applicable, and the TLAA is addressed in LRA Section 4.3.3. UFSAR Section 3.9(N).2.4 discusses the effects of FIV on the integrity of the RVI components. However, LRA Section 4.3.3 does not describe how the effects of FIV are being managed in the RVI components. It was not clear to the staff if cracking and loss of material induced by FIV are aging effects requiring management for the RVI components in LRA Table 3.1.2-3 and if the analysis is a TLAA, as defined in 10 CFR 54.3.

By letter dated January 5, 2011, the staff issued RAI 4.1-1, asking the applicant to clarify whether cracking induced by FIV or loss of material (i.e., wear or fretting) induced by FIV is an aging effect requiring management for the RVI components that are subject to aging management review (AMR). The staff also asked the applicant to clarify if its CLB includes any analysis that evaluated the impact of FIV on the structural integrity of the RVI components as a result of these aging mechanisms, and to explain if the analysis is a TLAA, as defined in 10 CFR 54.3. Furthermore, the staff asked the applicant to clarify if LRA Section 4.3.3 needs to be amended to include the analysis, in accordance with 10 CFR 54.21(c)(1).

In its response dated February 3, 2011, the applicant stated that its FIV analysis of the RVI was not performed as part of the CLB. The applicant stated that Westinghouse has studied FIV of PWR internals using in-plant and scale-model tests, as well as tests in fabricator's shops and bench tests of components to show the structural integrity and reliability of reactor internals components. The applicant stated that these results, and further analyses performed for its reactor internals, indicate that the effect of FIV on fatigue is extremely small and the stress level is well within the allowable stress based on the high cycle endurance limit for the materials. Therefore, the applicant concluded that there is no need to monitor the age-related effects of FIV on the fatigue of RVIs. The applicant did not amend LRA Table 4.1-3 to indicate that FIV analysis is not a TLAA. The staff noted that LRA Section 4.3.3 does not include any discussion on how the FIV analysis factors into the CUF calculations for the RVI core support structure components. The staff also noted that, in the response to RAI 4.1-1, the applicant indicated that there are "further analyses performed for the Seabrook Station reactor internals" for FIV of the RVI components. However, the applicant's response did not provide any comparison of these FIV analyses to the six criteria for TLAAs in 10 CFR 54.3. Therefore, the staff could not determine whether these additional analyses need to be identified as a TLAA for the LRA. This issue was combined with an issue on ductility reduction of fracture toughness, for which the staff issued followup RAI 4.1-1b. Discussion of this RAI is provided later in this section.

LRA Table 4.1-2 states that the analysis associated with ductility reduction of fracture toughness for the RVI components is applicable, and the TLAA is addressed in LRA Section 4.3.3. However, LRA Section 4.3.3 does not include a discussion related to this specific issue. The staff also noted that LRA Table 3.1.2-3 identifies loss of fracture toughness as an aging effect requiring management for the RVI components that are subject to an AMR. The staff noted that the service conditions that may degrade material properties of RVI components include neutron irradiation, temperature, and reactor coolant environment. It was not clear to the staff if the CLB includes any neutron fluence-dependent reduction of fracture toughness analysis for the RVI components or if the analysis is a TLAA, as defined in 10 CFR 54.3.

By letter dated January 5, 2011, the staff issued RAI 4.1-2, asking the applicant to clarify whether its CLB includes any neutron fluence-dependent reduction of fracture toughness analysis for the RVI components that are subject to an AMR in LRA Table 3.1.2-3. The staff also asked the applicant to explain if the analysis is a TLAA, as defined in 10 CFR 54.3, and if the LRA needs to be amended to include this analysis, in accordance with 10 CFR 54.21(c)(1).

In its response dated February 3, 2011, the applicant stated that the fluence-dependent reduction of fracture toughness of vessel internals is not analyzed as part of the CLB because this has been analyzed generically for all Westinghouse-designed plants. The applicant also stated that loss of fracture toughness due to irradiation is an aging management effect that will be managed by inspection and evaluation per its PWR Vessel Internals Program.

The staff noted the applicant's conclusion, that the analysis of ductility reduction of fracture toughness for the RVI is not a TLAA, is based on the determination that the analysis is not contained or incorporated by reference in the CLB. The staff noted that the applicant addressed the potential for a reduction in fracture toughness properties for the RVI components in its PWR Vessel Internals Program. The staff's evaluation of the PWR Vessel Internals Program is documented in SER Section 3.0.3.1.5. However, the applicant did not amend LRA Table 4.1-2 to indicate that ductility reduction of fracture toughness for the RVI is not part of its CLB, and LRA Section 4.3.3 does not include any discussion regarding how the ductility reduction of fracture toughness factor into the CUF calculations for the RVI core support structure components. The staff noted that the issues related to ductility reduction of fracture toughness are similar to those identified in the applicant's response to RAI 4.1-1 related to FIV. As a result, the staff combined the issues of FIV and ductility reduction of fracture toughness into followup RAI 4.1-1b.

By letter dated March 30, 2011, the staff issued RAI 4.1-1b, asking the applicant to amend LRA Table 4.1-2 to show that the issues of FIV and ductility reduction of fracture toughness are not

TLAAs and to provide the justification for making these changes to LRA Table 4.1-2. Otherwise, the staff asked that the applicant amend LRA Section 4.3.3 to clarify how the CUF calculations account for FIV in the RVI core support structures and the reduction in ductility or fracture toughness properties for the core support structures materials. The staff also asked the applicant to justify why the “further analyses” described in the LRA for FIV of the RVI components do not conform to the definition of a TLAA in 10 CFR 54.3.

In its response to RAI 4.1-1b dated April 22, 2011, the applicant revised LRA Table 4.1-2 to show that FIV and ductility reduction and loss of fracture toughness are not TLAAs. The applicant also stated that the analyses for FIV (including the "further analyses") and the reduction in ductility and fracture toughness are not incorporated in its CLB and do not involve a time-limited aging effect for the licensed operating period. Thus, the analyses do not meet all six criteria of a TLAA, defined in 10 CFR 54.3.

Based on its review, the staff finds the applicant’s response to RAI 4.1-1b acceptable because the applicant revised LRA Table 4.1-2 to show that the fatigue analyses for FIV in the RVI core support structures and the reduction in ductility or fracture toughness properties for the core support structures materials are not TLAAs. Additionally, the applicant explained that those fatigue analyses are not TLAAs, as defined in 10 CFR 54.3. The staff’s concern in RAI 4.1-1b is resolved.

Based on its review, the staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of cumulative fatigue damage on the intended functions of the specific locations of the RVI will be adequately managed for the period of extended operation because the staff has confirmed that the applicant will use its Metal Fatigue of Reactor Coolant Pressure Boundary Program to manage this aging effect during the period of extended operation, consistent with the recommendations of SRP-LR Section 4.3.2.1.1.3, by tracking the number of transient cycles that occur. This program also requires that the applicant take corrective actions prior to any analyzed number of cycles being reached in the applicable TLAA, which ensures that the analyses remain valid and the design limit of 1.0 is not exceeded.

In addition, based on its review, the staff also finds that the applicant has provided an acceptable basis for concluding that the LRA does not need to include any FIV, reduction of ductility or reduction in fracture toughness TLAAs for the RVI components because the staff has confirmed these type of analyses are not incorporated in or referenced by the CLB for the facility.

4.3.3.3 UFSAR Supplement

LRA Section A.2.4.2.2.2, as amended by letter dated June 2, 2011, provides the UFSAR supplement summarizing the metal fatigue TLAA of RVIs. The staff reviewed LRA Section A.2.4.2.2.2 consistent with SRP-LR Section 4.3.3.3, which states that the summary description should contain information associated with the metal fatigue TLAA of RVIs regarding the basis for determining that the applicant has made the demonstration required by 10 CFR 54.21(c)(1).

Based on its review of the UFSAR supplement, as amended by letter dated June 2, 2011, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.3. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address fatigue TLAA of RVIs, as required by 10 CFR 54.21(d).

4.3.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of cumulative fatigue damage on the intended functions of the RVIs 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).

4.3.4 Environmentally-Assisted Fatigue Analysis

4.3.4.1 Summary of Technical Information in the Application

LRA Section 4.3.4 describes the applicant's evaluation of the effects of reactor coolant environment on fatigue usage for the period of extended operation. The applicant stated that, although environmentally-assisted fatigue (EAF) analyses do not meet the definition of TLAA under 10 CFR 54.3 because they are not contained or incorporated by reference in its CLB, the discussion of EAF calculations is provided in response to the recommendation in SRP-LR, Revision 1, Section 4.3.2.2, "Generic Safety Issue," that applicants address the effects of the coolant environment on component fatigue life as aging management programs are formulated in support of license renewal. The applicant also stated that GALL AMP X.M1 provides an acceptable program that addresses 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. The applicant stated that NUREG/CR-6260 provides environmental fatigue calculations for a newer vintage Westinghouse plant, like Seabrook, for the locations of highest design CUF.

The 60-year CUFs obtained from the ASME air curve, and the EAF adjusted values for seven locations in the six NUREG/CR-6260 components, are summarized in LRA Table 4.3.4-1. The applicant stated that, for all locations, the ASME air-curve CUFs are less than 1.0 for the 60-year service. However, the 60-year EAF-adjusted CUFs exceed 1.0 for the hot leg surge line nozzle (HLSN) located on the pressurizer surge line (PSL) and the RCS charging nozzle. The applicant further stated that another acceptable option to disposition EAF is to manage fatigue of these components using the Metal Fatigue of Reactor Coolant Pressure Boundary Program by tracking the number and severity of plant transients and comparing with the design basis transients. Under this option, when the counted number of a specific plant transient reaches the plant design basis number associated with that transient, a preemptive remedial action described in the program will be undertaken by the applicant.

LRA Section 4.3.4 states that, based on NUREG/CR-6260, plant-specific components were identified, and the design ASME fatigue usage factors were adjusted by the environmental life correction factors (F_{en}) to obtain the environmentally-corrected CUF (CUF_{en}) for the RPV inlet and outlet nozzles, RPV shell and lower head, and residual heat removal (RHR) hot leg nozzle. The results for 60-year operation are summarized in LRA Table 4.3.4-1. LRA Section 4.3.4 also states that—for the RPV shell and lower head, RPV inlet and outlet nozzles, and RHR hot leg nozzle—the CUFs were determined using the number and severity of the design cycles of record, which bound the projected 60-year cycles and for these components. Furthermore, the environmental fatigue effects were determined using the maximum F_{en}, which incorporates the lowest strain rate, a temperature greater than 200° C, and dissolved oxygen level less than 50 parts per billion (ppb).

The applicant further stated that, for the remainder of the NUREG/CR-6260 locations (i.e., pressurizer surge line (PSL) nozzle, charging nozzle, and safety injection nozzle), the CUFs were determined using the projected 60-year cycles, and environmental effects were incorporated using an effective F_{en}. Based on the material at each location, F_{en} factors were determined for each transient pair using a temperature greater than 200° C, a dissolved oxygen level less than 50 ppb, and a strain rate that was calculated by the integrated strain rate method. The effective F_{en} factor for each location was then determined by the ratio of CUF_{en}/CUF. LRA Section 4.3.4 states that the fatigue analyses indicate that the 60-year CUF in air for all locations is less than the ASME design limit of 1.0, but the 60-year CUF adjusted for environmental effects is greater than 1.0 for the HLSN located on the PSL and the RCS charging nozzle.

The applicant dispositioned the EAF analyses for the RPV shell and lower head, and the RPV inlet and outlet nozzles, in accordance with 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation. The applicant also dispositioned the EAF analysis for the RCS PSL nozzle, RCS charging nozzle, RCS safety injection nozzle, and RCS RHR system Class 1 piping, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of reactor coolant environment on fatigue usage factors will be adequately managed for the period of extended operation using the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

4.3.4.2 Staff Evaluation

The staff noted that the applicant addressed the effects of the reactor coolant environment on component fatigue life, consistent with the guidance in the SRP-LR and the staff's recommendations for resolving Generic Safety Issue No. 190 (GSI-190), dated December 26, 1999. The staff also noted that, consistent with Commission Order No. CLI-10-17, dated July 8, 2010, the evaluations associated with the effects of the reactor coolant environment on component fatigue life do not fall within the definition of a TLAA in 10 CFR 54.3 because these evaluations are not in the applicant's CLB. Consistent with Commission Order No. CLI-10-17, the staff finds the applicant's evaluation of the effects of the reactor coolant environment on component fatigue life is an acceptable practice consistent with the staff's recommendations in the SRP-LR and the closure of GSI-190.

The staff reviewed LRA Section 4.3.4 and the EAF analyses for the RPV shell and lower head and the RPV inlet and outlet nozzles 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 Section 4.3.4 and the EAF analyses for RCS PSL nozzle, RCS charging nozzle, RCS safety injection nozzle, and RCS RHR system Class 1 piping to verify, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of reactor coolant environment on component fatigue life will be adequately managed for the period of extended operation using the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

The staff reviewed the applicant's evaluations and the corresponding disposition consistent with SRP-LR Section 4.3.3.2, which state that the reviewer should verify that the applicant has addressed the effects of the coolant environment on component fatigue life as AMPs that are formulated in support of license renewal. The SRP-LR also states that if the applicant has chosen to assess the impact of the reactor coolant environment on a sample of critical components, the reviewer should verify the following:

- The critical components include, as a minimum, those selected in NUREG/CR-6260.

- The sample of critical components has been evaluated by applying environmental correction factors to the existing ASME Code fatigue analyses.
- The formulae for calculating the F_{en} are those contained in NUREG/CR–6583, for carbon and low-alloy steels, and in NUREG/CR-5704, for austenitic SSs, or an approved technical equivalent.

During its review the staff identified that the applicant did not provide sufficient details on how the CUFs in air and the associated values of F_{en} were determined for the NUREG/CR-6260 locations listed in Table 4.3.4-1. It was not clear if all design transients were lumped together into the worst-case transient or if other transients were also considered in the fatigue analyses. The staff noted that LRA Section 4.3.4 states that the RHR system Class 1 piping analysis was based on its specific conditions, whereas footnote 4 of Table 4.3.4-1 states that this analysis was performed using design number and design-severity cycles. Therefore, it was not clear to the staff if the CUF analysis for the RHR system Class 1 piping was performed using plant-specific 60-year projected cycles or the design number and severity cycles.

By letter dated January 5, 2011, the staff issued RAI 4.3.4-2, asking the applicant to clarify if the 60-year ASME air-curve CUFs were calculated using ASME Code Section III NB-3200 or NB-3600 for each location listed in LRA Table 4.3.4-1. The staff also asked the applicant to describe how the transient definitions are selected and to justify the use of the integrated strain-rate method in the fatigue calculation and how it provides conservative results. Furthermore, the staff requested that the applicant clarify what the Seabrook-specific conditions are, as discussed in LRA Section 4.3.4, and to clarify if the CUF analysis for the RHR system Class 1 piping was performed using plant-specific conditions or using the design number and severity cycles, as noted in footnote 4 of LRA Table 4.3.4-1.

In its response dated February 3, 2011, the applicant stated that the 60-year ASME air-curve CUF values for all the components listed in LRA Table 4.3.4-1 were calculated using ASME Code Section III Subsection NB-3200. The applicant further stated that, in the integrated strain-rate method, F_{en} is computed at multiple points over the increasing (tensile) portion of a paired strain range. Additionally, an overall F_{en} is integrated over the entire tensile portion (i.e., from the algebraically lowest stress point of the maximum compressive stress event to the algebraically highest stress point of the maximum tensile stress event). The staff noted that the integrated strain-rate approach is rigorous because the strain-rate was computed for multiple points along the tensile portion of the paired strain range resulting in a more refined F_{en} value. The applicant also clarified that Seabrook-specific conditions are the 60-year projected number of cycles and design-severity cycles. The applicant stated that the RHR system Class 1 piping evaluation was not performed using plant-specific conditions but using the design number and severity of cycles, as noted in footnote 4 of LRA Table 4.3.4-1.

Based on its review, the staff finds the response to RAI 4.3.4-2 acceptable for the following reasons:

- The applicant clarified that the CUF analysis for the RHR system Class 1 piping was performed using the design number and severity of cycles.
- The applicant calculated F_{en} using a more rigorous integrated strain-rate method that results in a more refined F_{en} value.

The staff's concern described in RAI 4.3.4-2 is resolved.

LRA Section 4.3.4 discusses the methodology to determine the locations that require EAF analyses consistent with NUREG/CR-6260 “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components.” The staff recognized that, in LRA Table 4.3.4-1, there are seven plant-specific locations listed based on the six generic components identified in NUREG/CR-6260. However, the GALL Report AMP X.M1 states that the impact of the reactor coolant environment on a sample of critical components should include the locations identified in NUREG/CR-6260 as a minimum, and additional locations may need evaluation. During its review, the staff recognized that footnote 2 of LRA Table 4.3.4-1 states that these locations are plant-specific limiting locations within the boundary of the applicable NUREG/CR-6260 component. However, CUF values for other locations were not available in the LRA, and the applicant did not explain that these are the limiting locations for the plant. The staff noted that the applicant’s plant-specific configuration may contain locations that should be analyzed for the effects of the reactor coolant environment other than those identified in NUREG/CR-6260. This may include locations that are limiting or bounding for a particular plant-specific configuration or that could have CUF_{en} values that are greater when compared to the locations identified in NUREG/CR-6260.

The staff noted that LRA Section 4.3.2.2 stated that the controlling fatigue location of the PSL piping was the HLSN safe-end. However, footnote 2 in LRA Table 4.3.4-1 indicates the hot-leg surge nozzle-to-pipe weld to be the plant-specific limiting location within the boundary of the applicable NUREG/CR-6260 component locations.

By letter dated January 5, 2011, the staff issued RAI 4.3.4-1, Request 1, asking the applicant to provide the 40-year design CUF value and the projected 60-year CUF values (with and without environmental effects) for the HLSN safe-end. The staff also asked to applicant to clarify that the hot-leg surge-nozzle-to-pipe weld is the limiting location for the PSL.

In its response dated February 3, 2011, the applicant clarified that the HLSN-to-pipe weld was evaluated to be the limiting component in the surge line because it was reported to be the highest CUF in the surge line in the original analysis. The applicant also provided the 40-year design CUF and the projected 60-year CUF values for the HLSN safe-end. The applicant stated that the 40-year design CUF for the HLSN safe end is 0.6. A new analysis performed in support of the LRA, using the design-basis numbers of design-severity cycles, yielded CUF values of 0.52 in air and 6.63 in reactor environment. The applicant also stated that the CUF values for the same location, using the 60-year projected number of design-severity cycles, are 0.2844 in air and 3.2848 in reactor environment.

In its review, it was not clear to the staff whether the fatigue limiting CUF evaluations were performed for the nozzle-to-safe end weld or the safe end-to-pipe weld. In footnote 1 of Table 1 of the applicant’s response to RAI 4.3-1, the highest fatigue usage location is listed as nozzle transition and safe end, whereas in Table 2 of the applicant’s response to RAI 4.3.2-1, it is listed as nozzle safe end-to pipe weld. Furthermore, the staff noted inconsistencies in the CUF values listed in various tables. In LRA Table 4.3.4-1, for the HLSN-to-pipe weld, the 60-year CUFs are 0.2844 in air and 3.428 in reactor coolant environment, and the F_{en} factor is 12.05. In the response to RAI 4.3.4-1, for the HLSN safe-end, the 60-year CUFs are 0.2844 in air and 3.2848 in reactor coolant environment, and the F_{en} factor is 11.55.

By letter dated March 30, 2011, the staff issued followup RAI 4.3.4-1b, requesting that the applicant either resolve or justify the inconsistencies in the reported values of CUF, and clarify the fatigue limiting location of the HLSN.

In its response dated April 22, 2011, the applicant stated that the correct CUF for the HLSN-to-surge line weld is 0.2844, and the 60-year EAF-adjusted CUF is 3.428. The applicant stated that for the HLSN, which is an all-stainless steel configuration, the fatigue limiting location is the HLSN-to-surge line weld. The applicant revised LRA Table 4.3.4-1 to show the limiting location for the HLSN and the CUF values.

Based on its review, the staff finds the applicant's response to RAI 4.3.4-1b acceptable because the applicant revised the LRA clarifying that the fatigue limiting location of the HLSN and resolved the inconsistency in the 60-year EAF-adjusted CUF value for the HLSN-to-surge line weld. The staff's concern in RAI 4.3.4-1b is resolved.

By letter dated January 5, 2011, the staff issued RAI 4.3.4-1, Requests 2 and 3, asking the applicant to clarify that the plant-specific locations listed in LRA Table 4.3.4-1 are bounding for the generic NUREG/CR-6260 components. The staff also asked the applicant to confirm and justify that the locations selected for EAF analyses in LRA Table 4.3.4-1 consist of the most limiting locations for the plant (beyond the generic components identified in the NUREG/CR-6260 guidance). If these locations are not bounding, the applicant was requested to clarify the locations that require an EAF analysis and the actions that will be taken for these additional locations. Furthermore, if the identified limiting location consists of nickel alloy, the applicant must state if the methodology used to perform the EAF calculation for nickel alloy is consistent with NUREG/CR-6909 or justify the method chosen.

In its response dated February 3, 2011, the applicant stated that, at least 2 years prior to entering the period of extended operation, it will perform a review of design basis ASME Class 1 component fatigue evaluations. This review will determine if 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 Seabrook 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 the limiting location identified consists of nickel alloy, the EAF calculation for nickel alloy will be performed using the rules of NUREG/CR-6909.

The applicant further modified Commitment No. 44 of LRA Appendix A, Commitment List A.3, with the following:

> NextEra Seabrook will perform a review of design basis ASME 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 Seabrook 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 the limiting location identified consists of nickel alloy, the EAF calculation for nickel alloy will be performed using the rules of NUREG/CR 6909.

Based on its review, the staff finds the applicant response to RAI 4.3.4-1, Requests 2 and 3, and modified Commitment No. 44, acceptable for the following reasons:

- The applicant will review its design basis ASME Code Class 1 fatigue evaluations to determine if 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.
- Methodology consistent with NUREG/CR-6909 will conservatively be used in the evaluation if the limiting component identified consists of nickel alloy.
- Commitment No. 44 is consistent with the recommendations in SRP-LR Sections 4.3.2.2 and 4.3.3.2, and the GALL AMP X.M1, to consider environmental effects for the NUREG/CR-6260 locations, at a minimum.

The staff's concern in RAI 4.3.4-1, Requests 2 and 3, is resolved.

Based on its review, the staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses for the RPV shell and lower head and the RPV inlet and outlet nozzles have been projected to the end of the period of extended operation. This disposition is acceptable because the applicant has demonstrated that the CUF_{en}, when using the maximum F_{en} factor, is projected to remain below the design limit of 1.0 for the period of extended operation.

Based on its review, the staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the fatigue-related effects of reactor coolant environment on the intended functions of the RCS PSL nozzle, RCS charging nozzle, RCS safety injection nozzle, and RCS RHR system Class 1 piping, will be adequately managed for the period of extended operation. This disposition is acceptable because the applicant will continue to manage the effects of reactor coolant environment for these components with its Metal Fatigue of Reactor Coolant Pressure Boundary Program to ensure that the CUF_{en} values will not exceed the design limit of 1.0, or it will take corrective actions to reanalyze, repair, or replace the affected components.

4.3.4.3 UFSAR Supplement

LRA Section A.2.4.2.3 provides the UFSAR supplement summarizing the evaluation of the effects of reactor coolant environment on fatigue life of piping and components. The staff reviewed LRA Section A.2.4.2.3 consistent with SRP-LR Section 4.3.3.3, which states that the reviewer should verify that the applicant provided information, to be included in the UFSAR supplement, which includes a summary description of the evaluation of the effects of reactor coolant environment on fatigue. The SRP-LR also states that the reviewer should verify that the applicant has identified and committed in the LRA to any future aging management activities, including enhancements and commitments to be completed before the period of extended operation.

The staff also noted that the applicant committed (Commitment No. 44) to the following, as modified in its letter dated February 3, 2011:

- NextEra Seabrook will perform a review of design basis ASME 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 Seabrook 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 the limiting location identified consists of nickel alloy, the EAF calculation for nickel alloy will be performed using the rules of NUREG/CR-6909.

- Consistent with the Metal Fatigue of Reactor Coolant Pressure Boundary Program, Seabrook will update the fatigue usage calculations using refined fatigue analyses, if necessary, to determine acceptable CUFs (i.e., less than 1.0) when accounting for the effects of the reactor water environment. This includes applying the appropriate F_{en} factors to valid CUFs determined from an existing fatigue analysis valid for the period of extended operation or from an analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case).
- If acceptable CUFs cannot be demonstrated for all the selected locations, then additional plant-specific locations will be evaluated. For the additional plant-specific locations, if CUF, including environmental effects, is greater than 1.0 then corrective actions will be initiated, in accordance with the Metal Fatigue of Reactor Coolant Pressure Boundary Program. Corrective actions will include inspection, repair, or replacement of the affected locations before exceeding a CUF of 1.0 or the effects of fatigue will be managed by an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC).

Based on its review of the UFSAR supplement, as amended by letter dated February 3, 2011, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.3. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address the effects of reactor coolant environment on fatigue usage, as required by 10 CFR 54.21(d).

4.3.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant's evaluations on the effects of the reactor coolant environment on component fatigue life is not a TLAA as defined by 10 CFR 54.3 and is consistent with Commission Order No. CLI-10-17 (July 8, 2010). The staff also concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the effects of reactor coolant environment on fatigue usage of the RPV shell and lower head and RPV inlet and outlet nozzles has been projected to the end of the period of extended operation. The staff also concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of reactor coolant environment on fatigue usage of the RCS PSL nozzle, RCS charging nozzle, RCS safety injection nozzle, and RCS RHR system Class 1 piping, 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 evaluation, as required by 10 CFR 54.21(d).

4.3.5 Steam Generator Tube, Loss of Material and Fatigue Usage from Flow-Induced Vibration

4.3.5.1 Summary of Technical Information in the Application

LRA Section 4.3.5 describes the applicant's TLAA for steam generator tube loss of material due to wear and fatigue in the U-bend region resulting from FIV. The applicant stated that the TLAA for loss of material and fatigue of steam generator tubing addressed the impact of the power increase on the FIV as a result of its power uprates. The applicant stated that its pre-uprate analysis of the effects of FIV on tube wear and fatigue usage assumed 40 years of operation. The applicant also stated that its post-uprate analysis, when projected for 60 years of operation, showed that the increased wear loss did not exceed the acceptance limit of the original analysis. The applicant also stated that the fatigue usage computed for extended operation was zero because the steam generator tube bending stress, due to FIV, is below the fatigue endurance limit. The applicant also stated that a prerequisite for high cycle U-bend fatigue is a dented support condition at the upper tube support plate, and thus there is no concern for high cycle fatigue at Seabrook since the steam generators have stainless steel tube support plates.

The applicant dispositioned the TLAA related to steam generator tubes in accordance with 10 CFR 54.21(c)(1)(i), that the analyses of the loss of material due to wear and fatigue in the U-bend region of steam generator tubing remain valid for the period of extended operation.

4.3.5.2 Staff Evaluation

The staff reviewed LRA Section 4.3.5 to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses of the loss of material due to wear and fatigue in the U-bend region of steam generator tubing remain valid for the period of extended operation.

The staff reviewed the applicant's TLAAs and the corresponding disposition consistent with SRP-LR Section 4.3.3.1.1.1, which state that the staff should review the operating transient experience and a list of the assumed transients used in the existing cumulative usage factor (CUF) calculations for the current operating term to ensure that the number of assumed transients would not be exceeded during the period of extended operation.

The staff reviewed LRA Section 4.3.5 and determined that the applicant included, as an applicable aging effect, the loss of material due to the wear of the steam generator tube from flow-induced vibrations. The staff noted that the applicant discussed that the maximum 40-year wear is less than 0.0050 in. and the maximum 60-year tube wear will be 0.0075 in., and it concluded that the estimated maximum 60-year tube wall wear will be less than the acceptance criteria of 40 percent of wall thickness. The staff noted that the applicant did not provide the wall thickness of the tube to justify these statements.

By letter dated January 5, 2011, the staff issued RAI 4.3.5-2, asking the applicant to provide the tube wall thickness and to demonstrate that the estimated maximum 60-year tube wall wear is under the 40 percent of wall thickness acceptance limit. The staff also asked the applicant to explain why the TLAA analysis and disposition associated with tube wall wear should not be included as a stand-alone subsection under LRA Section 4.7 "Plant-Specific TLAA."

In its response dated February 3, 2011, the applicant stated that the nominal tube wall thickness for its 11/16-in. diameter tubes is 0.040 in. and explained that the estimated maximum 60-year tube wall wear will be less than the 40 percent of wall thickness acceptance criteria. The applicant also stated that the TLAA analysis and disposition associated with tube wall wear should be included as a stand-alone subsection under LRA Section 4.7 "Plant-Specific TLAA." The applicant amended its LRA to include LRA Section 4.7.15 "Steam Generator Tube Wall Wear From Flow-Induced Vibration."

Based on its review, the staff finds the applicant's response to RAI 4.3.5-2 acceptable because the applicant justified that the estimated maximum 60-year tube wall wear will be less than the acceptance criteria of 40 percent of wall thickness. Additionally, the applicant amended its LRA to include LRA Section 4.7.15 to discuss steam generator tube wall wear due to FIV. The staff's concern in RAI 4.3.5-2 is resolved. The staff's evaluation of loss of material due to the wear of the steam generator tube from FIV is documented in SER Section 4.7.15.2.

LRA Section 4.3.5 states that the evaluation showed that significant levels of tube vibration will not occur from either the fluidelastic or turbulent mechanisms above those associated with the pre-uprated condition. The staff noted that, over time, flow patterns may change, and the applicant's summary did not consider flow pattern changes when making the extrapolation from its 40-year analysis. In addition, LRA Section 4.3.5 states "[l]ow-cycle fatigue usage for the most limiting tube in the most limiting power-uprated operating condition resulting from the FIV tube bending stress is 0.2 [kips per square inch] ksi." The staff noted the applicant's statement implies that the low-cycle fatigue usage is 0.2 ksi.

By letter dated January 5, 2011, the staff issued RAI 4.3.5-1, Request 1, asking the applicant to provide its technical basis to support the linear extrapolation method and to demonstrate that its analysis envelops likely changes in wear and fatigue over the period of extended operation, as affected by FIV or fluid-structure interactions. The staff also asked the applicant to identify any past or future planned independent confirmation to ensure the validity of the analyses, and the adequacy of the confirmation for the period of extended operation.

The applicant's response to RAI 4.3.5-1, Request 1, dated February 3, 2011, that relates to wear is described and evaluated in SER Section 4.7.15. The staff noted that the applicant did not remove the wear-related (loss of material) discussion in the amended LRA Section 4.3.5.

As a part of its response to RAI 4.3.5-1, the applicant amended LRA Section 4.3.5, to, in part, change the disposition of the TLAA addressed in this section to 10 CFR 54.21(c)(1)(iii), that the effects of aging will be adequately managed for the period of extended operation by the Steam Generator Tube Integrity Program.

The staff noted that the fatigue evaluation documented in LRA Section 4.3.5 demonstrates that the 60-year CUF value is well below the design limit, which indicates how much margin is available before the design limit of 1.0 is reached. However, the staff noted that the Steam Generator Tube Integrity Program cannot be used to substitute an ASME Code Section III fatigue evaluation unless the applicant can justify and demonstrate that the AMP can address the fatigue-related CUF analysis. Therefore, the staff does not find the applicant's amendment to 10 CFR 54.21(c)(1)(iii) acceptable for the steam generator tube fatigue due to the FIV TLAA.

By letter dated March 30, 2011, the staff issued followup RAI 4.3.5-1b, asking the applicant to revise LRA Section 4.3.5 and move the wear-related (loss of material) discussion to LRA Section 4.7.15. The staff also requested that the applicant justify the TLAA disposition of the steam generator tube fatigue due to FIV in accordance with 10 CFR 54.21(c)(1)(iii) or revise the TLAA disposition of the steam generator tube fatigue TLAA due to FIV in accordance with 10 CFR 54.21(c)(1)(i).

In its response dated April 22, 2011, the applicant revised LRA Sections 4.3.5 and A.2.4.2.4 to focus only on steam generator tube fatigue usage due to FIV. The applicant also revised the TLAA disposition of the FIV fatigue usage to 10 CFR 54.21(c)(1)(i), which states that the analyses remain valid for the period of extended operation. The staff also verified that the applicant made the corresponding administrative change to LRA Table 4.1-1 associated with these LRA revisions.

Based on its review, the staff finds the applicant's response to RAI 4.3.5-1b acceptable because the change in TLAA acceptance basis for the FIV fatigue analysis is in accordance with 10 CFR 54.21(c). The staff's concern described in RAI 4.3.5-1b is resolved.

By letter dated January 5, 2011, the staff issued RAI 4.3.5-1, Request 2, asking the applicant to clarify the value for the low-cycle fatigue usage and the induced bending stress that is referenced in LRA Section 4.3.5. In its response to RAI 4.3.5-1, Request 2, dated February 3, 2011, the applicant indicated that the “0.2 ksi” referred to the alternating FIV bending stress and the value is below the fatigue endurance limit of 20 ksi at 1E+11 cycles. The applicant stated that the resulting fatigue usage is zero. The staff noted that when the bending stress range is less than the fatigue endurance limit, the resultant fatigue usage is zero.

Based on its review, the staff finds the applicant’s response to RAI 4.3.5-1, Request 2, acceptable because the applicant clarified that the fatigue usage factor of the most limiting steam generator U-bend tube will remain zero during the period of extended operation. The staff’s concern in RAI 4.3.5-1, Request 2, is resolved.

The applicant stated that a prerequisite for high-cycle U-bend fatigue is a dented support condition at the upper tube support plate, and there is no concern for high cycle fatigue because the steam generators have stainless steel tube support plates. The staff noted that, from industry experience in mid to late-1970s, denting resulted from the corrosion of the carbon steel support plates. The use of stainless steel tube support plate minimized the likelihood of denting. Thus, the staff finds it acceptable that the applicant concluded that high-cycle fatigue is not likely to occur.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the FIV fatigue analysis for the steam generator tube remains valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.1 because the number of assumed FIV cycles would not be exceeded during the period of extended operation.

4.3.5.3 UFSAR Supplement

LRA Section A.2.4.2.4, as amended by letter dated April 22, 2011, provides the UFSAR supplement summarizing the TLAA for steam generator tube fatigue in the U-bend region due to FIV. The staff reviewed LRA Section A.2.4.2.4 consistent with SRP-LR Section 4.3.3.3, which states that the summary description should contain information associated with the TLAA for steam generator tube fatigue regarding the basis for determining that the applicant has made the demonstration required by 10 CFR 54.21(c)(1).

Based on its review of the UFSAR supplement, as amended by letter dated April 22, 2011, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.3.2.3. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address steam generator tube fatigue, as required by 10 CFR 54.21(d).

4.3.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the FIV fatigue analysis for the steam generator tubes remains 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).

4.3.6 Absence of TLAAs for Fatigue Crack Growth, Fracture Mechanics Stability, or Corrosion Analysis Supporting Repair of Alloy 600 Materials

4.3.6.1 Summary of Technical Information in the Application

LRA Section 4.3.6 describes the applicant’s evaluations for fatigue crack growth, fracture mechanics stability, or corrosion issues supporting the repair of Alloy 600 materials.

Specifically, the applicant stated that the pressurizer contains Alloy 600 material only as Alloy 82/182 welds which are used to attach the pressurizer surge, spray, and relief valve nozzles to the safe ends and to attach the safe ends to the connecting piping. For these dissimilar metal welds, the applicant also stated that complete Alloy 690 structural weld overlays were performed during refueling outage 12 (spring 2008) as a mitigation measure, and these overlays were supported by fatigue crack growth analyses projected for a 60-year life. For this reason, the applicant concluded that these overlay fatigue crack growth analyses are not TLAAs.

LRA Section 4.3.6 also states that an RPV hot-leg nozzle Alloy 600 weld was mitigated through mechanical stress improvement process (MSIP) repair during refueling outage 13 (fall 2009). The applicant also stated that the MSIP repair for the vessel was supported by fatigue crack growth analysis projected for a 60-year life (the end of the period of extended operation); therefore, the applicant concluded that this analysis is not a TLAA.

4.3.6.2 Staff Evaluation

The staff reviewed LRA Section 4.3.6 and the applicant's evaluation for the absence of TLAAs for these fatigue crack growth analyses to verify the applicant's basis for concluding that there is no specific TLAA associated with the analyses performed to support the repair of Alloy 600 materials. The staff's review was performed in accordance with the review procedures in SRP-LR Section 4.1.3 and the acceptance criteria in SRP-LR Section 4.1.2, considering the clarification in Section III.g.(i) of the SOC for 10 CFR Part 54 (FRN Volume 60, No. 88).

The applicant's claim that the fatigue crack growth analyses that support the repair of Alloy 600 materials are not TLAAs is based on the determination that Criterion 3 of 10 CFR 54.3(a), the analysis involves time-limited assumptions defined by the current operating term, is not met. However, LRA Section 4.3.6 does not provide the details regarding the fatigue crack growth analyses for the pressurizer and the RPV to allow the staff to confirm the applicant's conclusion. The applicant stated that the fatigue crack growth analyses for both the pressurizer and the RPV were projected for a 60-year life, but it did not demonstrate why such analyses did not meet all of the six criteria identified in 10 CFR 54.3.

By letter dated January 5, 2011, the staff issued RAI 4.3.6-1, asking the applicant to explain the projection of the fatigue crack growth analyses performed for the pressurizer and RPV and justify why these analyses do not need to be identified as a TLAA.

In its response dated February 3, 2011, the applicant stated that the fatigue crack growth analyses performed for the pressurizer and the RPV weld repairs used a 43-year assumption that covers the entire period of extended operation for the relevant weld components. The applicant stated that the analyses should not be identified as a TLAA because Criterion 3 of 10 CFR 54.3(a) (the analyses involve time-limited assumptions defined by the current operating period) is not met.

Based on its review, the staff finds the applicant's response to RAI 4.3.6-1 acceptable because the applicant's fatigue flaw growth analyses for the pressurizer and the RPV weld repairs was performed to the end of the period of extended operation. Therefore, it does not meet Criterion 3 of 10 CFR 54.3(a).

The staff finds acceptable the applicant's conclusion that there is no specific TLAA that meets the requirements of 10 CFR 54.21(c)(1) and is associated with fatigue crack growth, fracture mechanics stability, or corrosion issues supporting the repairs of Alloy 600 materials, because the applicant has demonstrated that these analyses are not TLAAs, in accordance with Criterion 3 of 10 CFR 54.3(a).

4.3.6.3 UFSAR Supplement

On the basis of its review, the staff finds that a UFSAR supplement is not required because the analyses associated with fatigue crack growth, including fracture mechanics stability or corrosion analyses, supporting the repair of Alloy 600 materials address the period of extended operation and thus are not TLAAs.

4.3.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration that the analyses performed to support the repair of Alloy 600 material are not TLAAs. The staff also concludes that a UFSAR supplement is not required.

4.3.7 Non-Class 1 Component Fatigue Analyses

4.3.7.1 Summary of Technical Information in the Application

LRA Section 4.3.7 describes the applicant's fatigue TLAAs of the non-Class 1 piping and components designed in accordance with ASME Section III, Class 2 and 3. The applicant stated that the design of non-Class 1 piping and components in accordance with ASME Code Section III did not require an analysis based on the cumulative fatigue usage, rather the cyclic loading is considered in a simplified manner. The applicant noted that the design analysis compared the overall number of thermal and pressure cycles expected during the 40-year lifetime to cycle ranges specified in ASME Section III, Class 2 and 3 design codes, with consideration of allowable stress reduction if the total number of cycles exceeded 7,000.

The applicant stated that its TLAA assessment for 60-years of operation consisted of projecting the total number of applicable transient cycles for the period of extended operation, comparing these projections with the limit of 7,000, and assessing the fatigue impact if the projected cycles required a reduction in the allowable stress ranges. The applicant further stated that its assessment, even if all of the projected operational transients were added together, showed that there is no impact upon the original fatigue analyses used for these piping and components when designed to the ASME Section III, Class 2 and 3 requirements.

The applicant dispositioned the non-Class 1 piping and components fatigue analysis TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.3.7.2 Staff Evaluation

The staff reviewed LRA Section 4.3.7 and the non-Class 1 piping and components fatigue analyses to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with SRP-LR Section 4.3.3.1.2.1. These procedures state that the operating cyclic experience, and a list of the assumed thermal cycles used in the existing allowable stress determination, should be reviewed to ensure that the number of assumed thermal cycles would not be exceeded during the period of extended operation.

LRA Section 4.3.7 states that the applicant projected the number of cycles for various relevant transients to evaluate the TLAA for 60 years and then compared this projection to the 7,000 cycles considered in the original design. The staff noted that the 60-year projections are based on a linear extrapolation that uses the number of cycles accumulated through April 1, 2009. The staff confirmed that the total number of projected cycles for all applicable transients, provided in LRA Table 4.3.1-3, does not exceed the original design limit of 7,000 cycles, in accordance with ASME Code Section III, Subsections NC and ND.

SRP-LR Section 4.3.1.1.2 states that, for piping designed and analyzed to American National Standards Institute (ANSI) B31.1, allowable stress levels based on the number of anticipated thermal cycles are specified. The staff noted that UFSAR Table 3.2-2 indicates that the piping (downstream of the safety valves) of the pressurizer relief discharge system is designed to ANSI B31.1. The staff further noted that LRA Section 2.3.1.1 states that the pressurizer relief tank, pump, heat exchanger, and connected pipes and valves are within the scope of the license renewal. However, the applicant did not provide details regarding the applicable ANSI B31.1 piping and the associated TLAA in the LRA Section 4.3.7.

By letter dated January 5, 2011, the staff issued RAI 4.3.7-1, asking the applicant to clarify if there are any piping, piping components or piping elements—designed and analyzed in accordance with ANSI B31.1—that are within the scope of license renewal. The staff also asked the applicant to justify that LRA Section 4.3.7 provides adequate disposition of the fatigue-related TLAA for all non-Class 1 piping and components (including Class 2, Class 3, and ANSI B31.1).

In its response dated February 3, 2011, the applicant stated that, as shown in UFSAR Table 3.2-2, the principal design code is ANSI B31.1 for several sections of piping. Furthermore, these piping, piping components, or piping elements are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2), as a failure could affect a 10 CFR 54.4(a)(1) classified component. The applicant also stated that, as specified in LRA Section 4.3.7, the 60-year transient projection results shown in LRA Table 4.3.1-3 show that, even if all of the projected operational transients are added together, the total number of cycles projected for 60 years will not exceed the 7,000 cycles limit. Therefore, the allowable stress range does not need to be reduced as described in ASME Section III Class 2 and 3 and B31.1 rules.

However, the staff noted that the applicant did not amend LRA Section 4.3.7 to include the piping, piping components, and piping elements that were designed in accordance with ANSI B31.1 rules and are within the scope of license renewal. The applicant also did not identify that the evaluation performed in LRA Sections 4.3.7 and A.2.4.2.5 is applicable to the ANSI B31.1 piping. The staff noted that, in LRA Sections 4.3.7 and A.2.4.2.5, only ASME Section III, Class 2 and 3 components, were considered as non-Class 1 and dispositioned in accordance with 10 CFR 54.21(c)(1)(i). By letter dated March 30, 2011, the staff issued followup RAI 4.3.7-1b, requesting that the applicant revise LRA Section 4.3.7 and the applicable LRA Appendix A section to show that piping and piping components that were designed in accordance with ANSI B31.1 rules are included as part of the non-Class 1 piping and components addressed by this TLAA.

In its response dated April 22, 2011, the applicant revised LRA Sections 4.3.7 and Section A.2.4.2.5 to show that piping and piping components designed to ANSI B31.1 rules are within the scope of license renewal. The applicant also stated that the fatigue analysis of those B31.1 piping and piping components is dispositioned as part of the non-Class 1 piping in LRA

Section 4.3.7. Based on its review, the staff finds the applicant's response to RAI 4.3.7-1b acceptable because the applicant revised LRA Sections 4.3.7 and A.2.4.2.5 to include piping and components designed to ANSI B31.1, in accordance with SRP-LR Section 4.3.2.1.2.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the TLAA associated with fatigue analyses of non-Class 1 piping and components remain valid for the period of extended operation. Additionally, the applicant meets the acceptance criteria in SRP-LR Section 4.3.2.1.2.1 because the projected total number of cycles for all applicable transients over the period of extended operation does not exceed the 7,000 cycle limit.

4.3.7.3 UFSAR Supplement

LRA Section A.2.4.2.5, as amended by letter dated April 22, 2011, provides the UFSAR supplement summarizing the non-Class 1 piping and components fatigue analysis. The staff reviewed LRA Section A.2.4.2.5, consistent with SRP-LR Section 4.3.3.3, which states that the summary description should contain information associated with the evaluation of the non-Class 1 piping and components fatigue analyses.

Based on its review of the UFSAR supplement, as amended by letter dated April 22, 2011, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.3.2.3. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address the non-Class 1 piping and components fatigue analysis, as required by 10 CFR 54.21(d).

4.3.7.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the non-Class 1 piping and components fatigue 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).

4.4 Environmental Qualification (EQ) of Electrical Equipment

4.4.1 Summary of Technical Information in the Application

LRA Section 4.4 summarizes the evaluation of EQ of electrical equipment for the period of extended operation. The applicant stated that the Seabrook EQ of Electric Components Program implements aging management activities, which are credited for the management of aging in selected components within the scope of 10 CFR 54. The Seabrook EQ Program is an existing program that is consistent with NUREG-1801, GALL Report Section X.E1, "Environmental Qualification (EQ) of Electric Components." The applicant also stated that the program is administered in accordance with the Seabrook EQ Manual. The applicant further stated that as required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Aging evaluations for electrical components in the Seabrook EQ Program that specify a qualification of at least 40 years are TLAAs for license renewal because the criteria contained in 10 CFR 54.3 are met.

The applicant stated that, under 10 CFR Part 54.21(c)(1)(iii), the Seabrook EQ Program, which implements the requirements of 10 CFR 50.49 (as further defined and clarified by NUREG-0588, and RG 1.89, Revision 1), is viewed as an AMP for license renewal.

Reanalysis of an aging evaluation to extend the qualifications of components is performed on a routine basis as part of the Seabrook EQ Program. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met).

The applicant dispositioned the EQ requirements of electric components TLAA in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation. The applicant stated that the Seabrook EQ Program has been demonstrated to be capable of programmatically managing the qualified lives of the components within the scope of the program for license renewal. The continued implementation of the Seabrook EQ Program insures that the aging effects will be managed and that EQ components will continue to perform their intended functions for the period of extended operation.

4.4.2 Staff Evaluation

The staff reviewed LRA Section 4.4 on the TLAA associated with the EQ of Electrical Components Program to verify, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation. The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with SRP-LR Section 4.4.3.1.3. The staff's review of the EQ of Electrical Components Program is documented in SER Section 3.0.3.1.16.

The environmental qualification 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 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, a high-energy line break (HELB), or post-LOCA environment. EQ equipment comprises safety-related and Q-list equipment, nonsafety-related equipment 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, B.2,3.2, plant basis documents and interviewed plant personnel to verify whether the applicant provided adequate information to meet the requirement of 10 CFR 54.21(c)(1). For the 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. 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 functions, consistent with the CLB, for the period of extended operation. Per the GALL Report, plant EQ Programs that implement the requirements of 10 CFR 50.49 are considered acceptable AMPs under license renewal (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 components 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, Section B.2.3.2, 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. As evaluated in SER Section 3.0.3.1.16, the staff found that the EQ Program, which the applicant claimed to be consistent with GALL AMP X.E1, "Environment Qualification of (EQ) Electric Components," is consistent with the GALL Report. The staff further concludes that the applicant's EQ of Electrical 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.

In LRA Appendix A, Section A.2.4.3, the applicant provides the UFSAR summary description for the EQ of Electrical Equipment TLAA.

The staff reviewed the UFSAR supplement description of the program against the recommended description for this type of program, as described in SRP-LR Tables 4.4-1 and 4.4-2, and finds the UFSAR supplement consistent with the guidance of SRP-LR Tables 4.4.1 and 4.4.2.

The staff determined 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, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the environmental qualification of electrical equipment TLAA will be adequately managed for the period of extended operation. 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 Concrete Containment Tendon Pre-stress

4.5.1 Summary of Technical Information in the Application

LRA Section 4.5 summarizes the evaluation of concrete containment tendon pre-stress for the period of extended operation. The applicant stated that it has no TLAA associated with the concrete containment tendon pre-stress because the containment does not use pre-stressed tendons. Therefore, tendon pre-stress evaluations are not applicable.

4.5.2 Staff Evaluation

The staff reviewed relevant containment design information in the UFSAR to evaluate the validity of the applicant's basis. The staff noted that UFSAR Section 3.8.1.1 identifies the containment as a Category I reinforced concrete dry structure, which is designed to function at atmospheric conditions. The staff noted that UFSAR Section 3.8.1.1 states that the containment was designed as a seismic Category I conventionally reinforced concrete structure and does not use a pre-stressed concrete design. Based on this review, the staff verified that the design of the containment structure is not reinforced with pre-stressed tendons; therefore, the staff finds that this TLAA is not required. The staff also references its evaluation in SER Section 3.5.2.2.1.5 ("Loss of Prestress due to Relaxation, Shrinkage, Creep and Elevated Temperature").

4.5.3 UFSAR Supplement

The staff concludes that no UFSAR supplement is required because Seabrook has no pre-stressed tendons in the containment building.

4.5.4 Conclusion

On the basis of its review, the staff concludes that loss of pre-stress in concrete containment tendons is not a TLAA.

4.6 Containment Liner Plate Fatigue Usage and Containment Penetration Pressurization Cycles

4.6.1 Containment Liner Plate Fatigue Usage

4.6.1.1 Summary of Technical Information in the Application

LRA Section 4.6.1 describes the applicant's TLAA of the containment structure, which is a leak-tight membrane made of a welded carbon steel liner attached to the inside face of the concrete shell. The LRA states that fatigue of the containment liner plate was considered in the original design based on an assumed number of loading cycles that could occur during the life of the plant. The applicant determined that the Seabrook containment liner plate does not require analysis for cyclic service because it meets the criteria of ASME Section III Article NE-3221.5(d). The applicant further stated that the transients needing assessment for conformance with the ASME Section III Article NE-3221.5(d) exemption criteria are as follows:

- atmospheric-to-service pressure cycles and normal service pressure fluctuations
- temperature differences—startup and shutdown for similar and dissimilar materials
- mechanical loads

The LRA states that the anticipated stress cycles through 40 years of operation satisfy the exemption criteria of ASME Section III Article NE-3221.5(d), as follows:

- atmospheric-to-service pressure cycles (120 cycles)
- temperature differences from startup to shutdown (120 cycles)
- operating basis earthquake (OBE) (500 cycles)
- LOCA (10 cycles)

The LRA also states that the 40-year values were increased (linearly) by 50 percent to derive the projected values for 60 years of operation, and that the 60-year projections continue to satisfy the criteria of ASME Section III Article NE-3221.5(d).

The applicant dispositioned the containment liner plate fatigue TLAA, in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis has been projected to the end of the period of extended operation.

4.6.1.2 Staff Evaluation

The staff reviewed LRA Section 4.6.1, and the containment liner plate TLAA, 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 the applicant’s TLAA and the corresponding disposition, consistent with SRP-LR Section 4.6.3.1.1.2, which states that the operating transient experience and the list of the number of assumed cyclic loads projected to the end of the period of extended operation need to be satisfied to ensure that the cyclic load projection is adequate under the code of record.

The staff noted that the applicant evaluated the requirements for fatigue exemption using a linearly increased number of cycles to extend the analysis to the end of the period of extended operation. The staff also noted the applicant’s assertion that, with the increased number of cycles, the analysis continues to meet the requirements of ASME Section III Article NE-3221.5(d) for exemption from cyclic analyses. The staff reviewed Section 3.8 of UFSAR, titled “Design of Category I Structures,” but noted an apparent discrepancy in the stress cycles that were reported in the LRA initial exemption when compared to those reported in the UFSAR for the same exemption. In a teleconference held on May 5, 2011, the staff requested clarification of this discrepancy.

By letter dated April 16, 2012, the applicant responded by stating that the entry in UFSAR Section 3.8.1.3 titled “Loads and Loading Combinations,” under “a. Design Loads,” item 8 “Cyclic Loading,” shows the design loads for the containment liner plate. The applicant used these loads for the screening calculations to qualify the liner for the exemption from detailed fatigue analysis. The applicant further stated that it used the UFSAR-reported 120 cycles for plant startups and shutdowns for the exemption qualification requirements (e.g., because of the pressure and temperature relationship, the same cycles were used for both atmospheric-to-service pressure cycles and temperature differences during startup and shutdown.) The staff considered this input and did an independent code-based verification of the liner according to the requirements of ASME Section III Article NE-3221.5(d). The staff concluded that the liner plate meets the criteria set by the code to qualify it for the exemption from detailed fatigue analysis for the period of extended operation or for 60 years of operation.

During the May 5, 2011 teleconference, the staff also asked the applicant why 10 accident (LOCA) cycles were used in the fatigue exemption analysis instead of one cycle as stated in the UFSAR.

By letter dated April 16, 2012, the applicant responded that it used 10 cycles for conservatism in the TLAA analysis, but that the design basis load is one cycle as stated in the UFSAR. The staff found the approach acceptable because it provided a more conservative analysis for the code exemption. The staff's concern is resolved.

The staff finds that the applicant has demonstrated, pursuant to 10 CFR (c)(1)(ii), that the exemption analyses for the containment liner plate fatigue usage have been projected to the end of the period of extended operation.

Additionally, it meets the acceptance criteria in SRP-LR Section 4.6.2.1.1.2 because the analysis has been re-evaluated in accordance with the ASME code of record fatigue exemption criteria based on an increased number of cycles to cover the period of extended operation.

4.6.1.3 UFSAR Supplement

LRA Section A.2.4.4, “Fatigue of the Containment Liner and Penetrations,” provides the UFSAR supplement summarizing the TLAA of the containment liner plate. The staff reviewed LRA Section A.2.4.4 consistent with SRP-LR Section 4.6.3.2, which states that the applicant should provide a summary description of the fatigue evaluation of the containment liner and penetrations including the basis for determining that the applicant has made the demonstration required by 10 CFR 54.21(c)(1).

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.6.2.2. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address the TLAA of the containment liner plate, as required by 10 CFR 54.21(d).

4.6.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the TLAA of the containment liner plate is 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).

4.6.2 Pressurization Cycles: Personnel Airlock, Equipment Hatch, and Fuel Transfer Tube Assembly Absence of TLAA for Containment Penetrations

4.6.2.1 Summary of Technical Information in the Application

LRA Section 4.6.2 describes the applicant’s assessment of time-limited aging analyses (TLAAs) for the personnel airlock, equipment hatch, and the fuel transfer tube assembly containment penetrations. The LRA states that the designs of other containment penetrations designed to ensure a leak-tight membrane to contain the radioactive material released in the unlikely event of a loss of coolant accident (LOCA) are not TLAAs because they do not include any cyclic evaluations.

The LRA also states that the design of the Seabrook containment penetrations considered the design stresses against allowable stress limits independent of the number of load cycles and that there was no fatigue analysis. The applicant further stated that comparison to other containment systems designed by United Engineers and Constructors (UE&C) resulted in similar design criteria.

The applicant stated that the anticipated number of cycles for the personnel airlock, equipment hatch, and fuel transfer tube assembly projected to occur during the period of extended operation is bounded by the original design. The applicant stated that this basis is documented in UFSAR Section 3.8.2.3, and the cyclic loads considered in the design include 120 cycles of plant startup and shutdown, 400 OBE cycles, 100 SSE cycles, 1 accident cycle (LOCA), and 160 pressure test cycles. For the fuel transfer tube assembly, the cyclic loads considered are 400 OBE cycles, 1 accident cycle (LOCA), 160 pressure test cycles, and 1,000 temperature cycles.

The applicant dispositioned the personnel airlock, equipment hatch, and fuel transfer tube assembly penetration TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.6.2.2 Staff Evaluation

The staff reviewed LRA Section 4.6.2 and the personnel airlock, equipment hatch, and the fuel transfer tube assembly fatigue usage TLAA to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation, and to verify the applicant's claim that the design of other containment penetrations is not a TLAA.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with SRP-LR Section 4.6.3.1.1.1, which states that the number of assumed transients used in the existing CUF calculations for the current operating term should be compared to the extrapolation to 60 years of operation of the number of operating transients experienced to date. The comparison confirms that the number of transients in the existing analyses will not be exceeded during the period of extended operation.

The staff reviewed LRA Table 4.3.1-3 and found that the plant is designed to 200 temperature cycles, 50 OBE cycles, 1 SSE (10 cycles), and 1 LOCA. The personnel airlock and equipment hatch were designed to 400 OBE cycles, 100 SSE cycles, and 1 LOCA, which exceed the number of cycles used for those transients in the plant design. For the temperature cycles, however, the staff noted that the 120 cycles to which the personnel airlock and equipment hatch were designed are less than the cycles assumed in the original plant design. Although the 60-year temperature cycle projections of 87 heatup and 84 cooldown cycles (LRA Table 4.3.1-3) are bounded by the design fatigue analyses for the personnel airlock and equipment hatch, the staff was concerned that fatigue may not be considered if the plant approached or exceeded 120 cycles, since the NSSS design limits allow for 200 cycles.

In a conference call on November 22, 2011 the staff inquired how the applicant will track design limits related to plant startups and shutdowns as listed in LRA Section 4.6.2 related to the Equipment Hatch and Personnel Air Lock. In asking this question, the staff noted that in the applicant's response to RAI B.2.3.1-3 and RAI B.2.3.1-4 (Reference 3) the design limit tracked by FatiguePro is 200 Plant Heatups and Cooldowns with an 80% trigger level for further evaluation. The staff further noted that this action limit would exceed the design limit of 120 heatup and cooldown cycles for the Personnel Airlock and Equipment Hatch as specified in LRA section 4.6.2.

By letter dated December 15, 2011, the applicant stated that it had revised LRA Table 4.3.1-2 previously submitted in response to RAI B2.3.1-3 to include the specific plant startup and shutdown design limit of 120 cycles for the Personnel Airlock and Equipment Hatch. In addition, cycle counting for these specific components will initiate appropriate evaluations through the corrective action program if the 80% action limit is reached and this limit will be used by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for all limits tracked in FatiguePro. The applicant stated that this action limit will provide sufficient margin and time to allow for appropriate corrective actions as defined in the Metal Fatigue of Reactor Coolant

Pressure Boundary Program to be implemented prior to reaching the design limit. The staff reviewed the revised LRA Table 4.3.1-2 and confirmed that the applicant included a separate line item with a design limit of 120 cycles, which is specific only to the Personnel Airlock and Equipment Hatch analysis.

The applicant's December 15, 2011, letter confirmed that there were no additional non conservative design limits utilized in the TLAA for the Personnel Airlock and Equipment Hatch.

The staff finds the applicant’s supplement acceptable because (1) the applicant’s Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the design cycles (120 plant heatups and cooldowns) that were used in the fatigue analysis for the personnel airlock and equipment hatch will not be exceeded during the period of extended operation; (2) the program ensures sufficient time for corrective actions to be taken (i.e. reanalysis of the component, repair or replacement of the component) with an 80% action limit on the design cycles; and (3) the applicant confirmed that there are no other analyses that contain more limiting number of cycles that need to be incorporated into the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

The design of the fuel transfer tube assembly considers 400 OBE cycles, 1 LOCA, and 1,000 temperature cycles, all of which exceed the respective number of transients considered in the original plant design, so the existing fuel transfer tube assembly fatigue calculations for these transients will also remain valid for 60 years of operation.

As described in SER Section 4.7.5, the applicant's response to RAI 4.7.5-1 part (1), stated that the number of pressure test cycles considered in the personnel airlock, equipment hatch, and fuel transfer tube assembly designs is consistent with containment pressure testing. During the regional inspection the week of April 4, 2011, the staff asked the applicant whether the containment pressure testing referenced in the RAI 4.7.5-1 response referred to 10 CFR Part 50 Appendix J containment leak rate testing. The applicant confirmed that the referenced containment pressure testing is the Appendix J testing. The staff finds that the original design value of 160 pressurization cycles provides adequate margin for the period of extended operation because these loading cycles are in excess of the current cycles and those anticipated from projected Appendix J testing, as described in LRA Section B.2.1.31 for the 60 years of plant operation.

The staff finds the disposition of the TLAAs for the personnel airlock, equipment hatch, and fuel transfer tube assembly acceptable in accordance with 10 CFR 54.21(c)(1)(i), because the number of transients in the existing fatigue analyses will not be exceeded during the period of extended operation.

For the other containment penetrations, the staff reviewed UFSAR Section 3.8.2; subsections relating to piping, electrical, instrumentation, and ventilation penetrations; and the LRA. The LRA states that the design of the containment penetrations did not involve cyclic evaluations and, therefore, the designs are not TLAAs. The staff noted in the UFSAR that these five penetrations are designed according to the ASME Boiler and Pressure Vessel Code, Section III, Division 1, and that cyclic loading and fatigue was not considered in the original design.

In a teleconference held on May 5, 2011, the staff asked the applicant to confirm whether the design of any containment penetrations contained cyclic analyses.

By letter dated April 16, 2012, the applicant reaffirmed that these are not TLAAs and noted that its design engineer, United Engineers and Constructors, did not perform any cyclic analyses.

The staff reviewed the applicant's response and finds it acceptable because the current licensing basis does not include cyclic analyses, and therefore, the design of the penetrations does not meet the definition of a TLAA as stated in 10 CFR 54.3(a) Criterion 6. The staff's concern is resolved.

The staff finds the applicant has demonstrated pursuant to 10 CFR 54.21(c)(1)(i) that the analyses for the personnel airlock, equipment hatch, and fuel transfer tube assembly remain valid during the period of extended operation. The staff also finds that for the analyses of the other containment penetrations, TLAAs are not required.

4.6.2.3 UFSAR Supplement

LRA Section A.2.4.4 originally provided the UFSAR supplement summarizing the TLAA for the containment liner plate, and did not include the personnel airlock, equipment hatch, and fuel transfer tube assembly. By letter dated April 22, 2011, the applicant addressed the staff's observation of this inconsistency by amending LRA Section A.2.4.4 to summarize the TLAAs for the personnel airlock, equipment hatch, and fuel transfer tube assembly. The staff reviewed the amended LRA Section A.2.4.4 consistent with SRP-LR Section 4.6.3.2, which states that the applicant should provide a summary description of the fatigue evaluation of the containment liner and penetrations including the basis for determining that the applicant has made the demonstration required by 10 CFR 54.21(c)(1).

Based on its review of the UFSAR supplement, as amended, the staff finds it meets the acceptance criteria in SRP-LR Section 4.6.2.2. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address the TLAA of the personnel airlock, equipment hatch, and fuel transfer tube assembly, as required by 10 CFR 54.21(d).

4.6.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the TLAA of the personnel airlock, equipment hatch, and fuel transfer tube assembly 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). The staff further concludes that a TLAA is not required for the other containment penetrations.

4.7 Other Plant-Specific TLAA

An applicant may need to include a plant-specific analysis in the CLB as a TLAA for its LRA if the analysis conforms to the six criteria for TLAAs in 10 CFR 54.3. The NRC's recommended "acceptance criteria" and "review procedure" guidance on matters related to the acceptance of plant-specific TLAAs are given in SRP-LR Section 4.7 and its subsections.

SRP-LR Section 4.7.2 provides the staff's recommended "acceptance criteria" guidance for these TLAAs, and SRP-LR Section 4.7.3 provides the staff's recommended "review procedures" for these TLAAs. The subsections in SRP-LR Sections 4.7.2 and 4.7.3 provide the "acceptance criteria" and "review procedures" for accepting plant-specific TLAAs in accordance with the requirements of 10 CFR 54.21(c)(1)(i), 10 CFR 54.21(c)(1)(ii), or 10 CFR 54.21(c)(1)(iii).

4.7.1 Absence of a TLAA for Reactor Pressure Vessel Underclad Cracking Analyses

4.7.1.1 Summary of Technical Information in the Application

The applicant states that the growth of underclad cracks is not an applicable aging effect for Seabrook because the procedure qualification for laying down the cladding on the RPV low alloy steel components (SA-508, Class 2) required a special evaluation to assure freedom from underclad cracking, as described in the Seabrook UFSAR. Therefore, the applicant stated that no TLAA has been assigned in the CLB to the evaluation of cracking in the applicable RPV cladding-to-forging welds.

4.7.1.2 Staff Evaluation

The staff reviewed LRA Section 4.7.1 and pertinent information in the plant UFSAR to evaluate the validity of the applicant's basis.

The staff noted that RG 1.43 identifies that intergranular separations (i.e., underclad cracks) have been reported in SA-508, Class 2 RPV forgings when the vessel was manufactured with a cladding applied by a high-heat-input, submerged arc welding (SAW) process. According to this RG, there is a potential (although small) for these cracks to grow into the ferritic RPV shell as a result of cyclical loading. Therefore, Section 3.1.2.2.5 of the SRP-LR states that cyclic crack growth could occur and such growth is a TLAA that should be evaluated for the period of extended operation if the cladding was welded to the RPV SA-508, Class 2 forgings using a high-heat-input welding process. Such analyses may need to be identified as TLAAs for the LRAs if they conform to the six criteria for TLAAs in 10 CFR 54.3.

The staff verified that UFSAR Sections 5.2.3 and 5.3.1.4 indicate that the applicant applied the NRC's recommended weld control process in RG 1.43, "Control of Stainless Steel Weld Cladding of Low Alloy Steel Components," as the process for controlling the welding fabrication of the cladding to those RPV components that were fabricated from SA 508, Class 2 forging materials. The staff also verified that UFSAR Section 1.8 shows the applicant's procedural qualification was performed in accordance with the weld fabrication requirements in Sections III and XI of the ASME Code and in accordance with supplemental qualification criteria (i.e., Position C.2) of RG 1.43, which provides the staff's recommended welding qualification process controls for avoiding underclad cracking in these cladding-to-forging welds.

Therefore, given the applicant's special evaluation included the appropriate weld procedure qualification protocols for the cladding-to-forging welds, the staff determined that the RPV underclad cracking is not relevant in making a safety determination and, therefore, does not meet the definition of a TLAA, consistent with the requirements of 10 CFR 54.3(a)(4).

4.7.1.3 Conclusion

The staff concludes that there is not a TLAA for RPV underclad cracking because the RPV was manufactured with a cladding procedure that required a special evaluation and procedural qualification to assure freedom from underclad cracking. Therefore, according to the definition in 10 CFR 54.3(a)(4), this item is not a TLAA for Seabrook.

4.7.2 Reactor Coolant Pump Flywheel Fatigue Crack Growth Analyses

4.7.2.1 Summary of Technical Information in the Application

LRA Section 4.7.2 discusses reactor coolant pump (RCP) flywheel fatigue crack growth analyses. The applicant stated that Westinghouse Commercial Atomic Power (WCAP)-14535-A, “Reactor Coolant Pump Flywheel Inspection Elimination,” provided an engineering basis for elimination of RCP flywheel inservice inspection (ISI) requirements for all operating Westinghouse plants and certain Babcock and Wilcox plants. To be consistent with the defense-in-depth philosophy for protection against events or degradation mechanisms that are not anticipated or considered in the analysis, the NRC issued an SER in September 1996 that requires continuation of ISI with a 10-year inspection interval that coincides with RCP motor maintenance. Fatigue crack growth analyses that are included in the WCAP-14535-A report have been identified as a TLAA. The applicant stated that the number of cycles (pump starts and stops) used in this report (6,000 for a 60-year plant life) is substantially less than the 60-year cycle projection for the Seabrook RCP flywheels found in LRA Table 4.4.2-1. Therefore, any potential crack growth from an existing flaw would be minimal, and the analysis in the WCAP-14535-A report remains valid for the period of extended operation.

In LRA Table 4.4.2-1, the applicant provided the current and 60-year projected number of RCP start and stop cycles. Based on data obtained from Seabrook cycle-counting records to date and projecting the count to a 60-year EOL, the applicant concluded that the 60-year projection of RCP start and stop cycles for the four Seabrook RCPs will be no more than 536 cycles. The applicant concluded that the projected number of RCP starts and stops is not expected to exceed 6,000 cycles during the period of extended operation. The applicant dispositions this flywheel TLAA, in accordance with 10 CFR 54.21(c)(1)(i).

4.7.2.2 Staff Evaluation

SRP-LR Section 4 does not list RCP flywheel fatigue crack growth analyses as TLAAs that are generic to industry LRAs. As a result, the staff reviewed LRA Section 4.7.2 against the acceptance guidance in SRP-LR Section 4.7.2.1 for disposition of a plant-specific TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

The staff noted that RG 1.14, Revision 1, “Reactor Coolant Pump Flywheel Integrity” (August 1976), provides the staff’s recommended acceptance criteria for material and minimum fracture toughness properties of SA 508, Classes 2 and 3, materials and SA 533 Grade B, Class 2, materials used in the fabrication of U.S. RCP flywheels. RG 1.14, Revision 1, also provides guidelines for performing structural integrity assessments of the RCP flywheels in U.S. light-water reactors, including assessments for ensuring the integrity of the flywheels against unacceptable fatigue-induced crack growth failures.

The applicant stated that the fatigue crack growth assessments are based on the number of start-stop cycles assumed in the design specifications for the pumps. Therefore, to meet the 10 CFR 54.21(c)(1)(i) acceptance criterion, the applicant indicated that it must demonstrate that the total number of RCP start-stop cycles, projected through the end of the period of extended operation, will be bounded by the number of RCP start-stop cycles assumed in the fatigue crack growth analysis for the RCP flywheels.

The staff noted that the applicant is relying on the flaw growth analysis in WCAP-14535-A (ADAMS Accession No. ML9601290303) as the TLAA for the RCP flywheels. The staff verified that the NRC endorsed the methodology and results in this WCAP report in an SE dated September 12, 1996 (ADAMS Accession No. ML9609230010). However, in the conclusion section of the SE (Section 4.0), the staff concluded that that the inspections of the flywheels should be performed even if all of the recommendations of RG 1.14, Revision 1, were met, and the inspections of the RCP flywheels should not be eliminated. It was not clear to the staff from the TLAA discussion if the applicant intends to continue the inservice inspections of the RCP flywheels during the period of extended operation consistent with the position taken in the staff's SE of September 12, 1996, or if the applicant is proposing to discontinue the ISI examinations of the RCP flywheels during the period of extended operation.

By letter dated January 5, 2011, the staff issued RAI 4.7.2-1, asking the applicant to clarify if it is using the safety basis in the TLAA for the RCP flywheels to justify elimination of the RCP flywheel examinations altogether or if it intends to continue ISI of the RCP flywheels consistent the NRC's SE on WCAP-14535-A, dated September 12, 1996. If ISI will be performed during the period of extended operation, the staff also asked the applicant to explain what type of examinations will be performed on the RCP flywheels during the period of extended operation and the frequency that will be used for the examinations. Otherwise, the applicant was asked to justify its basis for discontinuing ISI of the RCP.

The applicant's February 3, 2011, response indicated that over the first 20 years of operation, all of the RCP flywheel inspections have been performed in accordance with TS requirements. During that time, no unacceptable indications have been found during the required surface and volumetric inspections. In addition, the applicant stated that, during the period of extended operation, Seabrook will continue the surface and volumetric inspections of the RCP flywheels on the required interval. However, the applicant did indicate that it was evaluating a license amendment request to change the inspection frequency from 10 years (current requirement) to 20 years.

The staff reviewed the applicant's February 3, 2011, response, Section 4.7.2 of the LRA, and WCAP-14535-A, along with the associated NRC SE. The staff determined that the projected start-stop cycles after 60 EFPY will be well below the 6,000 cycles used in fatigue flaw growth analysis of WCAP-14535-A. The staff also noted that the applicant will continue to perform surface and volumetric inspection every 10 years.

In summary, the staff finds the applicant's response to RAI 4.7.2-1, and the applicant's claim that the RCP flywheels will maintain their structural integrity during the period of extended operation acceptable, for the following reasons:

- The maximum number of start-stop cycles projected for 60 years (e.g., 536 start-stop cycles) have been demonstrated to be bounded by the 6,000 start-stop cycles limit assumed in the WCAP-14535-A fatigue flaw growth analysis.
- WCAP-14535-A has been endorsed for use in the staff's SE of September 12, 1996.
- Future inspections will be performed once every 10 years.

The staff's concerns described in RAI 4.7.2-1 are resolved.

Based on this review, the staff concludes that the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the fatigue analysis for the RCP flywheels has been demonstrated to remain valid for the period of extended operation.

4.7.2.3 UFSAR Supplement

The applicant provided an UFSAR supplement summary description of its TLAA evaluation of the RCP flywheel fatigue crack growth analysis in LRA Section A.4.4.2. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address RCP flywheel fatigue crack analyses is adequate.

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 fatigue crack analysis for RCP flywheels remains 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 Leak-Before-Break Analyses

4.7.3.1 Summary of Technical Information in the Application

LRA Section 4.7.3 describes the applicant's TLAA for leak-before-break (LBB) analyses for RCS primary loop piping. The applicant stated that these analyses were conducted to eliminate the need to consider dynamic effects of pipe ruptures from the design basis of the plant, as described in 10 CFR Part 50 Appendix A, "General Design Criteria for Nuclear Power Plants," Criterion 4, "Environmental and Dynamic Effects Design Bases." The applicant also stated that the fundamental premise of the LBB methodology is that the materials used in nuclear power plant piping are sufficiently tough that even a large through-wall crack would remain stable and would not result in a double-ended pipe rupture. The applicant further stated that the application of the LBB methodology is limited to those high-energy fluid systems not considered to be overly susceptible to failure from such mechanisms as corrosion, water hammer, fatigue, thermal aging, or indirectly from such causes as missile damage or the failure of nearby components.

The applicant dispositioned the LBB analyses TLAA for RCS primary loop pipe in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.7.3.2 Staff Evaluation

The staff reviewed LRA Section 4.7.3, LBB analyses for RCS primary loop pipe, to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with SRP-LR Section 4.7.3, which states that for certain applicants, plant-specific analyses may meet the definition of a TLAA as given in 10 CFR 54.3 and that these analyses may not have considered the length of the period of extended operation. The SRP-LR also states that this review will ensure that the aging effect under consideration will be properly addressed for the period of extended operation.

By letter dated August 9, 1984, the applicant requested an exemption from a portion of General Design Criterion 4 of Appendix A to 10 CFR Part 50 regarding the need to analyze large primary loop pipe ruptures as a structural design basis for Seabrook, Units 1 and 2. The staff notes that this exemption was granted in a letter from the NRC to the applicant dated November 22, 1985 (ADAMS Accession No. ML011790520). The staff also notes that this exemption was granted based on the LBB analysis contained in the SE attached to the November 22, 1985, letter and the Westinghouse Report, WCAP 10567 (proprietary). Based on this 1985 SE, the staff concludes that the LBB analysis conducted by the applicant is valid for the period of the original license for the conditions that existed at the plant at the time the analysis was conducted.

By letter dated March 17, 2004 (ADAMS Accession No. ML040850074), the applicant transmitted proprietary information to the NRC in support of its request for a power uprate license amendment. By letter dated February 28, 2005, the NRC granted the power uprate license amendment. The staff notes that the power uprate amendment was granted based in part on the staff's evaluation of the licensee's updated LBB analysis. This SE concluded that even after the effects of the power uprate were considered, the previously conducted LBB evaluation remained valid. Based on this 2005 safety analysis and the absence of additional changes to the applicant's license which could affect the validity of the LBB analysis during the current licensing period, the staff concluded that the applicant's LBB analysis remained valid for the current licensing period.

The staff notes that some of the components in the piping for which the leak before break analysis applies are constructed from cast austenitic stainless steel. This material is subject to thermal aging which reduces its fracture toughness. After some period of time at elevated temperature, the toughness of this material reaches a minimum. The staff also notes that the toughness of this material may or may not have reached its minimum before entry into the period of extended operation and that, depending on the toughness value used, the existing analysis may be valid for the current licensing period but not valid for the period of extended operation. The staff finally notes that specific statements are included in the LRA and the leak before break safety evaluations which indicate that the minimum toughness values expected for the cast austenitic stainless steel, irrespective of age, were used in the original leak before break analyses. The staff, therefore, finds that, from the perspective of material properties, the existing leak before break analyses will remain valid during the period of extended operation.

The staff notes that projections of the number of fatigue cycles which will be experienced by the plant are used in the fatigue crack growth calculation in the LBB analyses. The staff also notes that, in this case, the number of cycles used in the fatigue crack growth analysis was based on an anticipated plant life of 40 years. The staff further notes that plant operation beyond 40 years could invalidate the analysis if the actual number of cycles exceeds the predicted number of cycles. The staff finally notes that LRA Table 4.3.1-3 contains the 40-year projection of cycles used in the calculation, the actual number of cycles experienced to date, and the 60-year cycle projection based on current cycle accumulation rate. In all cases, the number of cycles currently expected in 60 years is less than the number of cycles considered in the original fatigue crack growth analysis. The staff, therefore, finds that, from the perspective of fatigue crack growth calculation, the existing LBB analyses will remain valid for the period of extended operation.

In Section 4.7.3 of the LRA, the applicant stated that mechanical stress improvement process (MSIP) had been performed at one of the RPV primary hot leg nozzle locations in 2009. This indicates that materials (Alloys 600/82/182) susceptible to primary water stress corrosion cracking (PWSCC) are present in the RCS primary loop piping, and PWSCC either has occurred or is considered highly likely to occur at this location. The staff notes that Section 3.6.3.III.3 of the SRP (NUREG 0800, Revision 1) states that in an LBB evaluation, the applicant must demonstrate that "PWSCC is not a potential source of pipe rupture." The staff also notes that SRP Section 3.6.3.III.7 states that "other regulatory guidance on LBB specifies that two mitigation methods are needed to address materials susceptible to an active stress corrosion cracking degradation mechanism."

Given that materials susceptible to PWSCC exist in the RCS primary loop piping, that there is a history of PWSCC in these materials, and that it appears that not all of the susceptible materials have been mitigated, it was not clear to the staff that the use of LBB analyses during the period of extended operation is consistent with NRC guidance on the subject. To resolve these issues, the staff issued RAI 4.7.3-1 by letter dated December 14, 2010. This RAI asked that the applicant:

- specifically identify the location of all materials which are susceptible to PWSCC in the piping systems covered by LBB analyses
- describe the inspection program covering these susceptible materials including inspections which monitor the growth of known indications
- describe in detail the results of these inspections including details on any known indications
- describe mitigation techniques that have been applied to these susceptible materials
- do one of the following:
  - demonstrate how the LBB analyses are consistent with Section III.3 of Part 3.6.3 of the SRP, that "PWSCC is not a potential source of pipe rupture" or Section III.7 of Part 3.6.3 of the Standard Review Plan, that "two mitigation methods are needed to address materials susceptible to an active stress corrosion cracking degradation mechanism"
  - describe how activities described above provide reasonable assurance that an LBB analysis, which considers the possibility of PWSCC is bounded by the existing LBB analysis
  - provide additional calculations that, considering the potential for PWSCC, demonstrate that the principles of LBB analyses are satisfied

In its response dated January 13, 2011, the applicant stated the following:

- LBB analyses are applicable only to reactor coolant loop piping.
- The inspection program for materials susceptible to PWSCC is documented in the Seabrook RCS Materials Degradation Management Reference Manual, which adheres to the guidelines documented in EPRI MRP-139.
- During refueling outage OR013 (fall 2009), all eight RPV nozzle butt welds were volumetrically inspected in accordance with MRP-139.
- During this inspection, a flaw indication connected to the inner diameter of the nozzle was identified on the RPV loop 158 degree hot leg nozzle.
- An MSIP repair was performed on this nozzle.
- As part of the MSIP repair, Westinghouse reviewed its impact on the LBB analyses for Seabrook, which is documented in WCAP-10567, "Technical Bases for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Seabrook Units 1 and 2, June 1984."

- As a result of that evaluation, the applicant concluded that the original LBB analysis remained valid.

The staff finds the applicant's response to this RAI acceptable for the 158 degree hot leg nozzle because the flaw on the 158 degree hot leg nozzle was mitigated by MSIP and the leak before break analysis has been reevaluated based on the mitigation. This is in accordance with staff guidance on the subject. The staff also finds the applicant's response to this RAI acceptable for the nozzles which have not been mitigated. This acceptance is based on two criteria. First, in "User Need Request On Development of a Probabilistic Method for Evaluating the Probability of Leak-Before-Break of Nickel Based Alloys Exposed to Primary Water Environments," (ML102140300), the staff states that "because of the high level of conservatism used in the traditional approach for LBB analysis, the staff is satisfied in the short term that adequate structural margins exist in all welds approved for LBB, even if PWSCC were occurring. The staff continues to gather and assess information to validate the continued existence of adequate margins." Second the staff notes that the inspection frequency for welds associated with leak before break contained in MRP-139 (and now ASME Code Case N77-1) is designed to be sufficient to detect cracking prior to rupture. The staff's concern described in RAI 4.7.3-1 is resolved.

The staff finds the applicant has demonstrated that, pursuant to 10 CFR 54.21(c)(1)(i), the applicant's LBB analyses for RCS primary loop pipe remain valid for the period of extended operation. This finding is based on the fact that the inputs for the two issues in the analyses, materials properties for the CASS and fatigue cycles used in the fatigue crack growth calculations, which were specifically based on the plant's original 40-year license were sufficiently conservative that the materials properties and the fatigue cycles bound those for the period of extended operation. Additionally, the applicant was able to demonstrate that the LBB analyses remain valid despite the existence of PWSCC susceptible material in LBB piping because the LBB analyses and other AMPs associated with PWSCC aging management (e.g., XI.M1, ASME ISI and XI.M11, Nickel Alloy Nozzles and Penetrations) are consistent with NRC guidance on the subject and provide appropriate aging management of the PWSCC susceptible material.

4.7.3.3 UFSAR Supplement

LRA Section A.2.4.5.2 provides the UFSAR supplement summarizing the LBB analyses of RCS primary loop piping. The staff reviewed LRA Section A.2.4.5.2 consistent with SRP-LR Section 4.7.2.2, which states that the summary description of the evaluation of TLAAs for the period of extended operation in the FSAR supplement is sufficient to demonstrate the basis for the applicant's assertion that 10 CFR 54.21(c)(1)(i) has been met.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address LBB analyses of RCS primary loop piping, 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 provided an acceptable demonstration that, pursuant to 10 CFR 54.21(c)(1)(i), the LBB analyses of RCS primary loop piping remain valid for the period of extended operation. The staff also concludes that the

FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.4 High-Energy Line Break Postulation Based on Cumulative Usage Factor

4.7.4.1 Summary of Technical Information in the Application

LRA Section 4.7.4 describes the applicant's TLAA for the CUF analyses for ASME Code Class 1 HELB locations. The applicant stated that its HELB analysis used a screening criterion of CUF greater than 0.1 to identify areas of investigation. The applicant indicated that UFSAR Section 3.6(B).2.1(a) eliminated locations in each piping run or branch run from further consideration as HELB locations on the basis that the CUF was less than 0.1 according to NUREG-0800, Revisions 1, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" Branch Technical Position MEB 3-1, "Postulated Rupture Locations in Fluid System Piping Inside And Outside Containment." The applicant also stated that its revised stress analysis permitted omission of the surge-line intermediate breaks based on CUF and that an LBB analysis eliminated large breaks in the main reactor coolant loops. The applicant concluded that the scope of the TLAA for HELB locations was limited to ASME Code Class 1 piping connected to the RCS from the primary coolant loops to the ASME Code Class 1 or Class 2 piping interface. The applicant stated that the applicable loading cycles projected for the 60-year period are bounded by the original design cycles.

The applicant dispositioned the TLAA for the CUF analyses of Class 1 HELB locations in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.7.4.2 Staff Evaluation

The staff reviewed LRA Section 4.7.4 and the TLAA for CUF analyses of ASME Code Class 1 HELB locations to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation. The staff reviewed this TLAA and the corresponding disposition by the applicant, consistent with SRP-LR Section 4.7.3.1.1. The SRP-LR states that the staff may accept the applicant's basis if the conditions and assumptions used in the analysis already address the relevant aging effects for the period of extended operation and the acceptance criteria provide assurance that the intended function(s) is maintained.

The staff reviewed UFSAR Section 3.6(B) and noted that it discussed eight primary reactor coolant loop locations that were approved in accordance with the applicant's LBB analysis. The staff noted that the LBB analysis permits an applicant to remove dynamic effect considerations from the scope of its large pipe LOCA analysis. The staff grants the use of an LBB analysis for the piping locations in compliance with the requirements in 10 CFR Part 50, Appendix A, GDC 4, "Dynamic Effects."

The staff's review of LRA Section 4.7.4 indicated that the applicant did not identify the ASME Code Class 1 RCPB locations in UFSAR Section 3.6(B) that are within the scope of the applicant's LBB analysis and the piping locations that are within the scope of the applicant's HELB CUF analyses. The staff also noted that LRA Section 4.7.4 dispositioned the TLAA in accordance with 10 CFR 54.21(c)(1)(i) without identifying the current CUF values or the design basis transients in LRA Table 4.3.1-2 that are applicable to the HELB locations. As a result, the staff could not determine if the disposition, in accordance with 10 CFR 54.21(c)(1)(i), is appropriate for the piping locations that are supported by the design transient projections in LRA Table 4.3.1-3.

By letter dated January 5, 2011, the staff issued RAI 4.7.4-1, requesting that the applicant:

- identify which ASME Code Class 1 piping locations discussed in UFSAR Section 3.6(B) are within the scope of the LBB analysis and LRA Section 4.7.3
- identify the ASME Code Class 1 piping locations discussed in UFSAR Section 3.6(B) that are within the scope of the CUF analyses discussed in LRA Section 4.7.4
- clarify whether the current design basis uses the LBB analysis to replace any of the original CUF analyses for HELB piping locations
- provide the CUF values and the design basis transients applicable to each HELB piping location within the scope of LRA Section 4.7.4
- provide the design cycle limits and 60-year projected cycle bases for the applicable transients, if the projections are included in LRA Table 4.3.1-3

In its response dated February 3, 2011, the applicant stated that all eight primary reactor coolant loop locations discussed in UFSAR Section 3.6(B) are the postulated break locations established by Westinghouse, as documented in report WCAP-8082. The applicant also stated that WCAP-10567 identified that the six safe-end welds enveloped the intermediate welds. Therefore, the applicant stated that all primary loop piping welds are within the scope of the LBB analysis and LRA Section 4.7.3. As a result, the applicant clarified that all intermediate Class 1 piping locations, with the exception of the primary loop locations eliminated by the LBB analysis in Section 4.7.3, were within the scope of HELB break postulation elimination on the basis of CUF. The applicant clarified that the current design basis does not use LBB analysis to replace any of the original CUF analyses for HELB piping locations.

The applicant also confirmed that there are 11 ASME Code Class 1 piping locations discussed in UFSAR Section 3.6(B) that are within the scope of the CUF analyses discussed in LRA Section 4.7.4 for which it performed a break elimination evaluation. The applicant provided the results from this evaluation as part of its response dated February 3, 2011. The applicant confirmed that the design basis transients shown in LRA Table 4.3.1-2 and the design cycle limits with 60-year projected cycles for the applicable transients, provided in LRA Table 4.3.1-3, are applicable for these HELB CUF evaluations. The staff noted that the highest design basis CUF value for the HELB locations was 0.085, and the current design basis CUF values for the HELB locations are all less than the design limit of 0.1.Consistent with SRP-LR Section 4.7.3.1.1, the staff compared the design basis cycle limits for all design transients listed in LRA Table 4.3.1-2 to their respective 60-year cycle projections, documented in LRA Table 4.3.1-3 (as amended by letter dated February 3, 2011). The staff's review and evaluation of the applicant's 60-year projections are documented in SER Section 4.3.1.2, which determined that the applicant provided an acceptable basis for projecting the number of cycles for the plant's design basis transients through 60 years of plant operation.

The staff noted that the 60-year projections for all design transients in LRA Table 4.3.1-3 are less than or equal to the design limit for these transients in LRA Table 4.3.1-2, which were the cycle inputs to the applicant's HELB CUF calculations. Thus, the staff confirmed that the number of cycles projected to occur through 60 years of operation is bounded by the number of cycles that were analyzed for in the applicant's HELB CUF calculations.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the HELB postulation based on CUF remain valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant demonstrated that the current HELB CUF analyses used conditions and assumptions that address the cumulative fatigue damage for the period of extended operation.

4.7.4.3 UFSAR Supplement

LRA Section A.2.4.5.3 provides the UFSAR supplement summarizing the TLAA for the HELB postulation based on CUF. The staff reviewed LRA Section A.2.4.5.3, consistent with SRP-LR Section 4.7.3.2, to verify that it contains information that the TLAA has been dispositioned for the period of extended operation.

Based on its review of the UFSAR supplement, and the applicant's response dated February 3, 2011, with acceptable resolution of the issues raised in RAI 4.7.4-1, the staff finds they meet the acceptance criteria in SRP-LR Section 4.7.3.1.1. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address the TLAA for the HELB postulation based on CUF, as required by 10 CFR 54.21(d).

4.7.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the TLAA for the HELB postulation based on CUF remains 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).

4.7.5 Fuel Transfer Tube Bellows Design Cycles

4.7.5.1 Summary of Technical Information in the Application

LRA Section 4.7.5 describes the applicant's TLAA for the evaluation of fuel transfer tube bellows design cycles for the period of extended operation. The LRA states that the fuel transfer tube assembly is comprised of a 24-in. diameter penetration sleeve penetrating through the containment and spent fuel building walls and three sets of expansion joints (bellows). The LRA also states that since this assembly performs a water-retaining intended function, the penetration sleeve and three bellows are within the scope of license renewal.

The LRA states that the fatigue analysis for the design of each of the three bellows is based on the consideration of 20 occurrences of the OBE with each having 20 seismic movement cycles. In order to determine if the design analyses remain valid for 60 years of operation, the applicant projected the number of seismic cycles likely to occur through the period of extended operation. The LRA further states that, as of January, 2010, the Seabrook transfer tube bellows have been exposed to zero (0) OBE cycles, and it projected that one (1) OBE would occur for Seabrook in 60 years of operation.

The applicant dispositioned the fuel transfer tube bellows design cycle TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.7.5.2 Staff Evaluation

The staff reviewed LRA Section 4.7.5 and the fuel transfer tube bellows design cycle TLAA to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the fatigue analyses of the fuel transfer tube bellows remain valid for the period of extended operation.The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with SRP-LR Section 4.7 for dispositioning plant-specific TLAAs.The adequacy of the bellows as part of the fuel transfer tube assembly is described in UFSAR 3.8.2.5, "Structural Acceptance Criteria," which discusses the ability of the bellows to sustain loads imparted under test, normal, upset and faulted conditions and the ability of the fuel transfer tubes to remain within the prescribed design basis loading limits. In accordance with the review procedures in SRP-LR Section 4.7.3.1.1, the staff needed more information to confirm that the applicant considered all possible design basis transients in the fatigue analysis for the fuel transfer tube bellows. By letter dated January 21, 2011, the staff issued RAI 4.7.5-1. In part (1) of RAI 4.7.5-1, the staff asked the applicant to confirm that all considerations with regard to cyclic loads due to the number of OBE occurrences, as well as the other transients such as the LOCA, pressure tests, and temperature cycles for the entire fuel transfer assembly used in the fatigue analysis were considered for the period of extended operation.

The applicant responded by letter dated February 18, 2011, and confirmed that all of the transients were considered for the entire fuel transfer tube assembly and that the cycles will be monitored by the enhanced cycle counting program, which is referenced in Commitment 42. This includes the design limits specified in the UFSAR for OBE cycles, accident cycle, pressure test cycles and temperature cycles. The number of temperature cycles is counted by monitoring to the number of plant heatup and plant cooldown cycles and the number of pressure test cycles is consistent with containment pressure testing. The accident cycle is counted as a faulted condition as listed in LRA Table 4.3.1-3.

The LRA states that the Seabrook fuel transfer tube bellows were designed to withstand 20 occurrences of the OBE. The UFSAR supplement also states that the fuel transfer tube bellows fatigue analysis is based on the consideration of 20 cycles of the OBE at 20 cycles maximum response (total of 400 cycles), but it further states that the design limit was five occurrences of 10 OBE cycles (total of 50 cycles). In part (2) of RAI 4.7.5-1, the staff asked that the applicant verify the number of OBE cycles used for the fatigue analysis.

In its response, dated February 18, 2011, the applicant clarified that the fatigue analysis for the fuel transfer tube bellows design is based on 20 occurrences of the OBE at 20 cycles each. The overall plant design for OBE is 50 cycles (five occurrences of 10 cycles.) The plant design transient limit listed in LRA Table 4.3.1-3 is more limiting and, therefore, the acceptance criteria for the transient is monitored to a value lower than analyzed for individual components (in this case, the fuel transfer tube bellows).

The staff's concern in RAI 4.7.5-1 is resolved. The plant design limit for OBE of five occurrences of 10 cycles is conservative for the fuel transfer tube bellows, which are designed to 400 cycles. This conservative estimate is still in excess of the one OBE that is projected to occur in 60 years of operation. The staff finds this acceptable because the design transients for the bellows exceed the NSSS design cycles for the plant.

The staff finds the applicant has demonstrated, pursuant to the requirements of 10 CFR 54.21(c)(1)(i) and the acceptance criteria in SRP-LR Section 4.7.2.1, that the fatigue analysis for the fuel transfer tube bellows remains valid during the period of extended operation.

4.7.5.3 UFSAR Supplement

LRA Section A.2.4.5.4 provides the UFSAR supplement summarizing the TLAA for the fuel transfer tube bellows design cycles. The staff reviewed LRA Section A.2.4.5.4 consistent with SRP-LR Section 4.7.3.2, which state that the applicant should provide a summary description of the fatigue evaluation of the containment vessel including the basis for determining that the applicant has made the demonstration required by 10 CFR 54.21(c)(1).

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally the staff determines that the applicant provided an adequate summary description of its actions to address the fuel transfer tube bellows design cycle TLAA, as required by 10 CFR 54.21(d).

4.7.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the fuel transfer tube bellows TLAA remains 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).

4.7.6 Crane Load Cycle Limits

4.7.6.1 Polar Gantry Crane

4.7.6.1.1 Summary of Technical Information in the Application

LRA Section 4.7.6.1 states that the design specification for the 420/50-ton polar crane in the containment structure required that it conform to the design requirements of Crane Manufacturers Association of America Specification Number 70 (CMAA-70), “Specifications for Electric Overhead Traveling Cranes.” The applicant also states that the service requirements specified for the design of this crane correspond to the cyclic loading requirements of CMAA-70, Class A, and, therefore, it is a TLAA.

According to the LRA, the polar crane was designed for up to 100,000 load cycles per criteria of CMAA-70 for service Class A. The applicant estimated that the polar crane will perform 19,440 lifts over the remaining 40 years of service, which includes 20 years of extended operation, with most of the lifts being less than 2,500 pounds. The LRA states that the rate is based on refueling outage use; therefore, the first 20 years of service life for the polar crane would include approximately 10,000 load cycles. Therefore, the total service life load cycles will be approximately 30,000.

The applicant dispositioned the polar gantry crane load cycle limit TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.7.6.1.2 Staff Evaluation

The staff reviewed LRA Section 4.7.6.1 to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation. The staff reviewed the applicant’s TLAA and the corresponding disposition, consistent with SRP-LR Section 4.7 for dispositioning plant-specific TLAAs.

The staff's review of the LRA Section 4.7.6.1 and Seabrook UFSAR Section 9.1.4.2 indicate that the containment polar gantry crane is designed in accordance with CMAA-70, which is recommended for crane design in NUREG-0612. The staff noted that, although the LRA states that the crane is designed to service Class A, the applicant's UFSAR does not specifically state the service class for the polar gantry crane. Since the applicant's CLB does not specify service class, the staff performed its review assuming no service class information was provided. The CMAA-70, service Class A is the most conservative service class, with a design rating of up to 100,000 cycles. According to the applicant, the estimated number of lifts is based on refueling outage use, which for the first 20 years of service life includes approximately 10,000 load cycles. The applicant has projected that for the remaining 40 years of service through the end of the period of extended operation, the polar crane would experience 19,440 additional lifts, thus the total number of load cycles over the service life will be approximately 30,000. The staff believes that 30,000 lifts is a conservative number of lifts that the crane will experience through the end of the period of extended operation and the estimate is less than the 100,000 load cycles allowable for a Class A crane. Therefore, the staff has determined that the polar crane can continue to operate and the existing fatigue analysis will remain valid for the period of extended operation.

Based on its review, the staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the polar crane remains valid for the period of extended operation because the crane is designed for more cycles than the maximum expected number of cycles during 60 years of operation.

4.7.6.1.3 UFSAR Supplement

The applicant provided an UFSAR supplement summary description of its TLAA evaluation of the load cycle limits of the containment polar crane in LRA Section A2.4.5.5.1. The polar crane is designed for more than the maximum number of load cycles for the period of extended operation. Based on its review of the UFSAR supplement, the staff concludes that the applicant provided an adequate summary description of its actions to address the crane load cycle limits.

4.7.6.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis for the polar crane TLAA remains 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).

4.7.6.2 Cask Handling Crane

4.7.6.2.1 Summary of Technical Information in the Application

In LRA Section 4.7.6.2 the applicant states that the cask handling crane was replaced in 2008 by a single failure-proof crane, designed to the requirements of ASME NOG-1-2004, NUREG-0554, and NUREG-0612. The crane is also designed to CMMA-70, "Specifications for Electric Overhead Traveling Cranes," with an allowable design life cycle range of up to 100,000 cycles.

The applicant states that, although the crane became operational in 2008, the bridge structure is original equipment. The applicant further states that the projected number of lifts for the cask handling crane is less than 500, and the estimate is based upon the expected number of casks that must be handled during each cask loading campaign and the projected number of campaigns through the period of extended operation. The applicant allowed for double that number for minor lifts, or 1,000 cycles, for a total of 1,500 cycles.

The applicant dispositioned the cask handling crane load cycle limit TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.7.6.2.2 Staff Evaluation

The staff reviewed LRA Section 4.7.6.2 and Seabrook UFSAR Section 9.1.4.2 to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation. The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with SRP-LR Section 4.7 for dispositioning plant-specific TLAAs.

The staff reviewed FSAR Section 9.1.4.2 and found that the cask handling crane is designed to the requirements of CMAA-70, ASME NOG-1-2004, and NUREG-0554.

The applicant based the analysis of the cask handling crane on the load cycles experienced by the bridge structure, since it has been in service through the entire period of plant operation. The applicant's UFSAR does not specify the service class for which the cask handling crane was designed. The minimum number of cycles for all cranes designed to CMAA-70 is 100,000 cycles; since no service class is specified in the CLB, it is conservative to assume 100,000 cycles as the allowable design life cycle upper limit. The applicant stated that it included a conservative estimate of 1,500 lifts over 60 years, which includes 500 Cask Handling Crane lifts for 60 years of plant operation and an additional 1,000 cycles for minor lifts. The staff finds the estimate to be realistic because the cask handling crane is only used for handling spent fuel storage casks. Spent fuel storage casks are normally lifted infrequently, including when they are ready to be transported outside the fuel building. The estimate of 1,500 cycles over 60 years is significantly less than the 100,000 cycles for which the crane is designed. Therefore, the staff has determined that the existing fatigue analysis for the cask handling crane will remain valid for the period of extended operation.

Based on its review, the staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the cask handling crane remain valid for the period of extended operation because the crane is designed for more cycles than the maximum expected cycles for 60 years of operation.

4.7.6.2.3 UFSAR Supplement

The applicant provided an UFSAR supplement summary description of its TLAA evaluation of the load cycle limits of the cask handling crane in LRA Section A2.4.5.5.2. Based on its review of the UFSAR supplement, the staff concludes that the applicant provided an adequate summary description of its actions to address the crane load cycle limits.

4.7.6.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the cask handling crane TLAA remains valid for the period of extended operation. The staff also concludes the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.7 Service Level I Coatings Qualification

4.7.7.1 Summary of Technical Information in the Application

LRA Section 4.7.7 describes the applicant's TLAA for qualification of Service Level I coatings. The applicant stated that, during a design basis accident (DBA), the emergency core cooling system (ECCS) at Seabrook could potentially be negatively impacted by detached coating debris contributing to blockage of the ECCS suction strainers. The applicant assumes that the radiation exposure used in the original DBA testing of the Service Level 1 coatings was intended to bound 40 years of operation. Thus, the applicant has determined that continued performance of Service Level 1 coatings is a TLAA.

The applicant dispositioned the Service Level I coatings qualification TLAA in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation. The applicant indicated that the Seabrook Service Level I coatings are managed by the Protective Coatings Monitoring and Maintenance AMP.

4.7.7.2 Staff Evaluation

The staff reviewed LRA Section 4.7.7 and the Service Level I coatings qualification TLAA, to verify, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation. The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with SRP-LR Section 4.7 for dispositioning plant-specific TLAAs.

In the LRA, the applicant stated that the operability of the ECCS suction strainers in providing long-term cooling is a requirement per 10 CFR 50.46(b)(5). The applicant provided a comprehensive list of coated surfaces inside containment in UFSAR Table 6.1(B)-2 that have the potential of being exposed to a post-LOCA environment. It was indicated in the LRA that the qualification of the coatings to withstand the effects of radiation and the DBA conditions assures that the coatings will remain intact and will not contribute to clogging of ECCS strainers beyond analyzed limits. The applicant stated that the Protective Coatings Monitoring and Maintenance AMP manages cracking, blistering, flaking, peeling, and delamination of the Service Level 1 coatings, consistent with the guidelines of Regulatory Position C4 of NRC RG 1.54, Revision 1, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants," as described in NUREG 1801, Revision 1. In addition, the applicant stated that the coatings used in Service Level 1 applications are qualified and applied in accordance with the requirements of the following documents:

- NRC RG 1.54, ANSI N101.4-1972, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities"
- ANSI N101.2-1972, "Protective Coatings (Paints) for Light Water Nuclear Containment Facilities"
- ANSI N512-1974, "Protective Coatings (Paints) for the Nuclear Industry"

The staff finds that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of the applicant's TLAA for qualification of Service Level I coatings will be adequately managed for the period of extended operation because the applicant will use its Protective Coating Monitoring and Maintenance Program to manage coating degradation effects during the period of extended operation. Additionally, the staff finds that the TLAA meets the acceptance criteria in SRP-LR Section 4.7.3.1.3 because the applicant will use the Protective Coating Monitoring and Maintenance AMP, which the staff determined in SER Section 3.0.3.2.20 to be consistent with GALL AMP XI.S8.

4.7.7.3 FSAR Supplement

LRA Section A.2.4.5.6 provides the FSAR supplement summarizing the Service Level I qualification TLAA. The staff reviewed the LRA Section A.2.4.5.6 consistent with SRP-LR Section 4.7.3.2, which states that the applicant must provide information that includes a summary description of the evaluation of each TLAA. The SRP-LR also states that each such summary description is reviewed to verify that it is appropriate such that later changes can be controlled by 10 CFR 50.59. The SRP-LR further states that the description should contain information that the TLAAs have been dispositioned for the period of extended operation.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.3.2. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address qualification of Service Level I coatings, as required by 10 CFR 54.21(d).

4.7.7.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of Service Level I coatings will be adequately managed for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.8 Absence of a TLAA for Reactor Coolant Pump: Code Case N-481

4.7.8.1 Summary of Technical Information in the Application

LRA Section 4.7.8 describes the absence of a TLAA for RCPs when using ASME Code Case N-481, “Alternative Examination Requirements for Cast Austenitic Pump Casings.” ASME Boiler and Pressure Vessel Code, Section XI, specifies that a volumetric inspection of the RCP casing welds and a visual inspection of pump casing internal surfaces be performed on a RCP within each 10-year inspection period. The applicant stated that, since these inspections are difficult to perform, ASME Code Case N-481 was developed to allow for the replacement of volumetric examinations with fracture mechanics-based evaluations, supplemented by specific visual inspections. The applicant also stated that its pump casings are cast in one piece, eliminating welds in the casing; in addition, support feet are cast integral with the casing, eliminating any weld region. The applicant further stated that, per UFSAR Section 5.4.1.4, the RCPs can be inspected in accordance with the ASME Code, Section XI, for ISI of nuclear RCSs. The applicant concluded that, since the pump casings were cast in one piece and do not contain welds, ASME Code Case N-481 is not applicable to the RCPs.

4.7.8.2 Staff Evaluation

The staff reviewed LRA Section 4.7.8 to verify, pursuant to 10 CFR 54.3, that a TLAA of the ASME Code Case N-481 for RCPs is not applicable. The staff reviewed the applicant’s evaluation and conclusion, consistent with SRP-LR Section 4.1.3, which states that the review verifies that the selected analyses do not meet at least one of the six criteria of a TLAA as defined in 10 CFR 54.3.

The staff reviewed the applicable ASME Code Section XI requirements, the alternative inspection requirements of ASME Code Case N-481, and the applicant's UFSAR. The staff noted that Code Case N-481 was developed to provide alternative examination requirements of cast austenitic pump casings because the weld inspections that are required by ASME Code Section XI would involve a large amount of time, resources, and radiation exposure. The staff reviewed UFSAR Figure 5.4-17, "Reactor Coolant Pump Supports," and UFSAR Section 5.4.1.4, "Tests and Inspections," for the RCPs and confirmed that the pump casings are cast in one piece. The staff finds that since the pump casings are cast in one piece, this eliminates welds in the casings, and since the support feet are cast integral with the casing, this eliminates a weld region. UFSAR Section 5.4.1.4 also states that the design of the RCPs enables the disassembly and removal of the pump internals for visual access to the internal surface of the pump casing. Based on its review, the staff concluded that the applicant can inspect the internal surface of the RCPs in accordance with the ASME Code Section XI for ISI of RCPs without invoking Code Case N-481.

Based on its review, the staff finds the applicant's conclusion, that there is no specific TLAA associated with ASME Code Case N-481, acceptable because the applicant demonstrated that its CLB does not contain analyses related to the Code Case N-481 for the RCP casings. Therefore, ASME Code Case N-481 is not a TLAA, in accordance with Criterion 6 of 10 CFR 54.3(a).

4.7.8.3 UFSAR Supplement

On the basis of its review, the staff finds that an UFSAR supplement is not required because this TLAA is not applicable, as described above.

4.7.8.4 Conclusion

On the basis of its review, the staff concludes that that the applicant provided an acceptable demonstration that ASME Code Case N-481 is not applicable to its RCPs and, therefore, is not a TLAA. The staff also concludes that an UFSAR supplement is not required.

4.7.9 Canopy Seal Clamp Assemblies

4.7.9.1 Summary of Technical Information in the Application

LRA Section 4.7.9 describes the fatigue analyses for the canopy seal clamp assemblies. The application describes that the original fatigue analyses considered the forces that would be applied to the center head adapter, which maximized the moments on the J-grove weld and the moment along the length of the adapter. The applicant stated that the design fatigue analyses for the canopy seal clamps are based on the consideration of 400 cycles consisting of 20 occurrences of the OBE, each occurrence having 20 cycles of maximum response. The applicant projected the number of seismic cycles for 60 years in order to determine if the design analyses remain valid for 60 years of operation. The applicant stated that, as of January 2010, the canopy seal clamps have been exposed to zero OBE cycles. The applicant projected that only one OBE with 20 seismic cycles would occur in 60 years of operation and, therefore, the fatigue analyses remain valid for the period of extended operation since it is conservatively bounded by the design values. The applicant concluded that the canopy seal clamp assemblies are shown to be acceptable for the period of extended operation, in accordance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(i).

4.7.9.2 Staff Evaluation

The staff reviewed LRA Section 4.7.9 and the canopy seal clamp assemblies TLAA to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the fatigue analyses of the canopy seal clamp assemblies remain valid for the period of extended operation. The staff reviewed the applicant’s TLAA and the corresponding disposition, consistent with SRP-LR Section 4.7 for dispositioning plant-specific TLAAs.

The staff noted that fatigue analyses were performed for the canopy seal clamp assemblies, but it was not clear if the analyses referred to fatigue crack initiation or fatigue flaw growth. If these were fatigue flaw growth analyses, detailed information regarding the initial flaw size, loading cycle assumption, and critical flaw size are needed for the staff to evaluate the applicant’s TLAA disposition. In addition, the staff reviewed LRA Sections 3.1 and 4.7.9 and noted that the aging effect of the canopy seal clamp assemblies was not identified. The staff noted that the design fatigue analyses were based on the consideration of 400 cycles (20 occurrences of the OBE and each OBE has 20 cycles of maximum response); however, LRA Table 4.3.1-3 projects only one occurrence of an OBE with 10 cycles during its 60-year operation.

By letter dated January 5, 2011, the staff issued RAI 4.7.9-1, requesting that the applicant:

- clarify the aging effect of the canopy seal clamp assemblies in LRA Section 4.7.9 and justify that the TLAA disposition is appropriate for the aging effect of the canopy seal clamp assemblies
- clarify whether the fatigue analyses are crack initiation analyses or flaw growth analyses
- clarify and justify the use of a different number of cycles during an OBE earthquake in different sections of the LRA

In its response to RAI 4.7.9-1, Request 1, dated February 3, 2011, the applicant stated that there is no specific aging effect identified for the canopy seal clamp assemblies. However, there is an aging effect identified for the head adapters since fatigue analyses were developed using design transients over the current operating term. The applicant stated that it conservatively classified the analyses associated with the head adapters as a TLAA to verify that the assumptions of the analyzed design transients remain bounded for the period of extended operation.

LRA Section 4.7.9, as amended by letter dated February 3, 2011, states that the canopy seal clamp assemblies were designed for a 40-year design life and the analyses were performed for the head adapters. The staff reviewed LRA Table 3.1.2-2, “Reactor Vessel,” and could not identify an AMR line item for the head adapters that addresses this aging effect. The staff also noted that the applicant has not identified the relationship between the canopy seal clamp assemblies and the head adapters or explained how the head adapter’s 60-year evaluation supports the canopy seal clamp assemblies design life basis for meeting the stress limits. Furthermore, the staff noted that LRA Section A.2.4.5.7 was not revised to reflect the revisions to LRA Section 4.7.9, as a result of RAI 4.7.9-1. By letter dated March 30, 2011, the staff issued followup RAI 4.7.9-1b, requesting that the applicant:

- identify the AMR line item, in the LRA Section 3, that is applicable to the head adapters as required by 10 CFR 54.21(a)(1) or justify that an AMR line item is not needed for the head adapters
- explain how the head adapter's 60-year TLAA evaluation supports the canopy seal clamp assemblies design life basis for meeting the stress limits
- provide an updated UFSAR supplement section in LRA Appendix A commensurate with the changes in LRA Section 4.7.9

In its response to RAI 4.7.9-1b, Request 1, dated April 22, 2011, the applicant stated that the head adapters are commonly referred to as the canopy seal pressure housing within its documents and are reflected in AMR Table 3.1.2-2. The staff reviewed LRA Table 3.1.2-2 and confirmed that the applicant has included canopy seal pressure housing with an aging effect of cumulative fatigue damage and credited this TLAA for managing this aging effect.

In its response to RAI 4.7.9-1b, Request 2, dated April 22, 2011, the applicant stated that it had not provided an adequate response to RAI 4.7.9-1 in its letter dated February 3, 2011. LRA Section 4.7.9, as amended by letter dated April 22, 2011, now states that the canopy seal pressure housings have been exposed to zero OBE cycles, and the projected number of OBE cycles will remain below the seismic movement cycles used in the analyses. LRA Table 4.1-1 was also amended to clarify that LRA Section 4.7.9 applies to canopy seal pressure housings.

In its response to RAI 4.7.9-1b, Request 3, dated April 22, 2011, the applicant provided an amendment to LRA Section A.2.4.5.7 commensurate with the changes in LRA Section 4.7.9.

Based on its review, the staff finds the applicant's response to RAI 4.7.9-1b acceptable because LRA Table 3.1.2-2 includes an AMR line to address the aging effect associated with canopy seal pressure housings as required by 10 CFR 54.21(a)(1), and LRA Sections 4.7.9 and A.2.4.5.7 have been revised to address canopy seal pressure housings. The staff's concerns described in RAI 4.7.9-1b, Requests 1, 2, and 3, are resolved.In its response to RAI 4.7.9-1, Requests 2 and 3, dated February 3, 2011, the applicant clarified that the fatigue analyses for the head adapters, in LRA Section 4.7.9, refer to fatigue crack initiation analyses. The applicant also stated that the head adapters design fatigue analyses assumed 400 OBE cycles. The applicant stated that an OBE is one of the reactor coolant design transients, and the associated NSSS design limit is 50 cycles (five occurrences of 10 cycles) as shown in UFSAR Table 3.9(N)-1. The staff noted that both the projected 20 cycles (one OBE occurrence with 20 seismic cycles) in LRA Section 4.7.9, or the 50 cycles of the NSSS design limit in UFSAR Table 3.9(N)-1 are well below the head adapters' design limit of 400 cycles.

Based on its review, the staff finds the applicant's response to RAI 4.7.9-1, Requests 1, 2, and 3, acceptable for the following reasons:

- The applicant clarified that the fatigue analyses identified in LRA Section 4.7.9 are fatigue crack initiation analyses for the canopy seal pressure housing.
- There is a significant margin between the projected number of seismic cycles and the head adapters' design limit of 400 cycles.

The staff's concern described in RAI 4.7.9-1, Requests 1, 2, and 3, is resolved.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the fatigue analyses for the canopy seal pressure housings remain valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because, for the canopy seal pressure housings head adaptor, the projected number of 60-year OBE cycles is far less than the design limit.

4.7.9.3 UFSAR Supplement

LRA Section A.2.4.5.7 provides the UFSAR supplement summarizing the canopy seal clamp assemblies fatigue analyses. The staff reviewed LRA Section A.2.4.5.7, consistent with SRP-LR Section 4.7.2.3, to verify that it contains information that the TLAA has been dispositioned for the period of extended operation.

In its response to RAI 4.7.9-1b, Request 3, dated April 22, 2011, the applicant amended UFSAR supplement Section A.2.4.5.7 to specify that the scope of the UFSAR supplement summary description for the canopy seal clamp assembly fatigue analyses included the canopy seal pressure housings. The staff finds that this change is acceptable because it consistent with the changes that were made to the TLAA for the canopy seal assemblies in the RAI response letter of April 22, 2011, and the UFSAR supplement for this TLAA.

RAI 4.7.9-1b, Request 3, is resolved with respect to UFSAR supplement A.2.4.5.7.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address the canopy seal clamp assemblies analyses, as required by 10 CFR 54.21(d).

4.7.9.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to10 CFR 54.21(c)(1)(i), that the analyses for the canopy seal clamp assemblies 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).

4.7.10 Hydrogen Analyzer

4.7.10.1 Summary of Technical Information in the Application

LRA Section 4.7.10 describes the radiation dose analysis for the hydrogen analyzer. The applicant stated that the UFSAR addresses accumulated radiation dose limits for a 40-year operating period. In addition, the post-accident hydrogen analyzer must perform its safety function following a LOCA, and the resulting excessive radiation exposure could jeopardize its ability to perform this safety function. UFSAR Table 6.2-84 defines the hydrogen analyzer design parameter and maximum radiation dose limit of 5×10^6 rads for 40 years of normal operation.

Based on the one-year predicted integrated dose, the applicant stated that the maximum predicted 60-year dose for the hydrogen analyzer is 4.32×10^5 rads. The applicant concluded that this is an order of magnitude less than the specified UFSAR radiation dose limit; therefore, the hydrogen analyzers are shown to be acceptable for the period of extended operation, in accordance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(i).

4.7.10.2 Staff Evaluation

The staff reviewed LRA Section 4.7.10 and the hydrogen analyzer radiation dose TLAA to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation. The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with SRP-LR Section 4.7 for dispositioning plant-specific TLAAs.

The staff reviewed LRA Section 2.3.2.1 and LRA Table 3.2.2-1 and noted that the hydrogen analyzer is not included in the AMR of license renewal. The staff also noted that UFSAR Section 6.2.5 states that the hydrogen analyzer is a safety-related component. By letter dated January 5, 2011, the staff issued RAI 4.7.10-1, asking the applicant to identify the aging effect associated with the hydrogen analyzer and justify that the TLAA and its disposition are appropriate for the associated aging effect. The staff also asked that the applicant justify that the AMR results provided in LRA Table 3.2.2-1 adequately address the aging effect for the hydrogen analyzer.

In its response dated February 3, 2011, the applicant stated that the hydrogen analyzer was included as a TLAA because the radiation dose limits of the analyzer was based on a 40-year period, as described in UFSAR Table 6.2-84. The applicant also stated that the hydrogen analyzer is an active component within the scope of license renewal, and, in accordance with 10 CFR 54.21(a)(1)(i), active components do not require AMR. The staff reviewed the combustible gas control system license renewal boundary drawing PID-1-CGC-LR20612 and confirmed that the hydrogen analyzer panels and associated piping components are within the scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 4.7.10-1 acceptable because the staff confirmed that the hydrogen analyzer is within the scope of license renewal and the hydrogen analyzer is not subject to an aging management review since it is an active component in accordance with 10 CFR 54.21(a)(1)(i). The staff's concern described in RAI 4.7.10-1 is resolved.

The staff reviewed UFSAR Section 6.2.5, "Combustible Gas Control System," and UFSAR Table 6.2-84, "Hydrogen Gas Analyzer Design Parameters." The staff noted that UFSAR Table 6.2-84 lists the 40-year radiation dose limit for the hydrogen analyzer as $5x10^6$ rads. LRA Section 4.7.10 states that the hydrogen analyzer has an annual dose rate of $7.2x10^3$ rads, which is equivalent to a 60-year dose of $4.32x10^5$ rads. The staff noted that, as discussed in UFSAR Section 6.2.5.2, the hydrogen analyzer is located outside the containment, where the radiation dose is less than that inside the containment. The staff noted that this 60-year dose is bounded by the current UFSAR limit ($5x10^6$ rads).

The staff finds that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis for the radiation dose for the hydrogen analyzer remains valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the 60-year radiation dose for the hydrogen analyzer is less than the radiation dose limit, and there is significant margin between the 60-year radiation dose and the radiation dose limit.

4.7.10.3 UFSAR Supplement

LRA Section A.2.4.5.8 provides the UFSAR supplement summarizing the hydrogen analyzer dose analysis. The staff reviewed LRA Section A.2.4.5.8 consistent with SRP-LR Section 4.7.2.2, which states that the description should contain information associated with the

TLAA regarding the basis for determining that the applicant has made the demonstration required by 10 CFR 54.21(c)(1).

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address the dose analysis for the hydrogen analyzer, as required by 10 CFR 54.21(d).

4.7.10.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to10 CFR 54.21(c)(1)(i), that the radiation dose analysis for the hydrogen analyzer remains 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).

4.7.11 Mechanical Equipment Qualification

4.7.11.1 Summary of Technical Information in the Application

LRA Section 4.7.11 describes the TLAA associated with environmental qualification (EQ) of mechanical equipment. The applicant stated that its CLB commits to the review and evaluation of the EQ of mechanical equipment to demonstrate compliance with General Design Criteria 4 of Appendix A to 10 CFR Part 50. The applicant further stated that the design basis event conditions during the period of extended operation will remain the same as those in the current license period, having already been adjusted to account for previously approved power uprate conditions. Therefore, the design basis event parameters—including the temperature, pressure, and time profiles—do not require further evaluation as TLAAs for license renewal. However, since a period of 40 years was used to determine the normal service radiation exposure to the equipment, the applicant considers mechanical equipment qualification (MEQ) a TLAA.

In order to determine if the design analyses remain valid for 60 years of operation, the applicant proposed to revise the calculations for MEQ prior to entering the period of extended operation using techniques currently used under the CLB for equipment qualification including analytical methods, replacement of radiation sensitive materials, or equipment replacement. The applicant dispositioned the MEQ TLAA in accordance with 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation.

4.7.11.2 Staff Evaluation

The staff reviewed LRA Section 4.7.11 and the MEQ TLAA 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 the applicant's TLAA and the corresponding disposition, consistent with SRP-LR Section 4.7.3.1.2, which states that the applicant shall provide a sufficient description of the analysis and document the results of the reanalysis to show that it is satisfactory for the period of extended operation.

SRP-LR Section 4.4 states that some nuclear plants have mechanical equipment that was qualified in accordance with the provisions of Criterion 4 of Appendix A to 10 CFR 50, and, if this qualified mechanical equipment requires the performance of a TLAA, it should be performed in accordance with the provisions of SRP-LR Section 4.7.

The staff noted that, in UFSAR Section 3.11.2, the environmental parameters of interest are temperature, pressure, humidity, radiation, chemical spray, and submergence. The applicant stated that the effects of aging on the intended function of equipment will be adequately addressed for the period of extended operation. Commitment No. 45 was provided in the LRA, Appendix A, indicating that the MEQ files will be revised prior to the period of extended operation. It was not clear to the staff if the applicant has accounted for the environmental parameters described in UFSAR Section 3.11.2 in addition to those that were listed in the LRA. It is also not clear to the staff what the "time profiles" being referred to in LRA Section 4.7.11 are. The staff noted that the applicant did not identify the 40-year radiation exposure limit, the projected 60-year radiation exposure limit, nor the design limit for the radiation exposure of the safety-related active mechanical equipment. Without this information, the staff is not able to evaluate the adequacy of the applicant's disposition for this TLAA. Furthermore, it was not clear if the applicant will revise all or only selected MEQ files, and it was not clear what type of information will be re-evaluated and revised when Commitment No. 45 is implemented.

By letter dated January 5, 2011, the staff issued RAI 4.7.11-1, Request 1, asking the applicant to clarify that all environmental parameters identified in UFSAR 3.11.2 have been evaluated and accounted for during the period of extended operation and to clarify what the "time profiles" being referred to in LRA Section 4.7.11 are.

In its response dated February 3, 2011, the applicant stated that only the normal service radiation exposure was subject to a TLAA. The applicant also stated that none of the other environmental parameters were based on a 40-year interval. The applicant stated that MEQ does not have time-based thermal aging requirements, and the time profiles referenced in the LRA Section 4.7.11 refer to design basis event conditions that do not change due to license renewal and, therefore, do not need to be re-evaluated as a TLAA.

Based on its review, the staff found the applicant's response to RAI 4.7.11-1, Request 1, acceptable because the applicant clarified that only the normal service radiation exposure was based on a 40-year interval in the MEQ. Additionally, Criterion 3 of 10 CFR 54.3 states that, in order to be considered a TLAA, the original analyses should involve a time-limiting assumption. The staff's concern described in RAI 4.7.11-1, Request 1, is resolved.

By letter dated January 5, 2011, the staff issued RAI 4.7.11-1, Requests 2, 3, and 4, asking the applicant to identify the 40-year radiation exposure limit, the projected 60-year radiation exposure limit, and the design limit for the radiation exposure of the safety-related active mechanical equipment. The staff also asked the applicant to ensure that the radiation exposure has been appropriately accounted for in the TLAA. The staff also requested that the applicant explain how LRA Section 4.7.11 and Commitment No. 45 satisfy its disposition in accordance with 10 CFR54.21(c)(1)(ii) and amend Commitment No. 45 to delineate the information to be re-evaluated and revised.

In its response dated February 3, 2011, the applicant stated that it has a calculation of EQ zone total-integrated radiation dose design values for a 60-year plant life, which provides values for various environmental zones. The applicant also determined that the 60-year dose limits are bounded by the existing equipment design dose limits. The staff noted that there is not sufficient information to determine if this TLAA of normal service radiation exposure in MEQ has been appropriately dispositioned. The staff noted that LRA Section 4.7.11, as amended by letter dated February 3, 2011, does not discuss the detail regarding the calculated dose limits and equipment design dose limits for normal service radiation exposure.

The applicant also stated in the response that the evaluation of normal radiation exposure for MEQ has been completed and is available in a license renewal technical report. The applicant stated that, as listed in Table A.3 in LRA Appendix A, Commitment No. 45 will track the formal revision of the MEQ files prior to the period of extended operation. The applicant explained that LRA 4.7.11 already defines the scope of the TLAA as being limited to normal service radiation exposure, and Commitment No. 45 is applicable to all MEQ files. The applicant also revised LRA Section 4.7.11, which states that the effects of aging on the intended functions of equipment listed in the MEQ have been projected to be bounded by existing equipment design limits for the period of extended operation. Furthermore, the applicant revised LRA Section A.2.4.5.9 to state that the effects of aging have been projected to be bounded by existing equipment design limits, in accordance with 10 CFR 54.21(c)(1)(ii), for the period of extended operation.

The staff finds the applicant's disposition, in accordance with 10 CFR 54.21(c)(1)(ii), not appropriate because the existing analyses on equipment design dose limits has not been revised and extended. The applicant demonstrated that the existing analyses on equipment design dose limits are bounding for the projected 60-year doses for all zones. The staff noted that this demonstration of the normal service radiation exposure is consistent with a disposition in accordance with 10 CFR 54.21(c)(1)(i). However, SRP-LR Section 4.7.3.1.1 states that, for the disposition of 10 CFR 54.21(c)(1)(i), the existing analyses should be shown to be bounding for the period of extended operation. Furthermore, the applicant did not amend Commitment No. 45 and stated that LRA 4.7.11 already defines the scope of the TLAA as being limited to normal service radiation exposure. The staff finds the applicant's response unacceptable because Commitment No.45 did not identify what portion of the MEQ file will be revised and the acceptance criteria of the revision.

By letter dated March 30, 2011, the staff issued followup RAI 4.7.11-1b, asking the applicant to provide the design dose limits of the equipment within the scope of MEQ and the calculated total integrated radiation 60-year doses for all the zones. The staff also asked the applicant to ensure that the TLAA of normal service radiation exposure in MEQ has been properly dispositioned. The staff also asked the applicant to amend LRA Section 4.7.11 and provide sufficient detail to support the TLAA disposition of normal service radiation exposure in MEQ. Furthermore, the staff asked the applicant to revise Commitment No. 45 to identify the information to be revised and the acceptance criteria of the revision or justify why the existing Commitment No.45 is acceptable. Finally, the staff asked the applicant to amend the disposition of TLAA of normal service radiation exposure in MEQ to 10 CFR 54.21(c)(1)(i) or justify why the existing TLAA disposition of 10 CFR 54.21(c)(1)(ii) is acceptable. If LRA Section 4.7.11 is amended as a result of RAI 4.7.11-1b, the RAI stated that the applicant should provide an updated UFSAR supplement section in LRA Appendix A consistent with the revisions.

In its response dated April 22, 2011, the applicant provided information about component types, radiation limiting environmental zones, calculated 60-year total integrated doses, and design dose limits for the equipment within the scope of MEQ. The applicant concluded that the calculated 60-year total integrated doses are bounded by the existing equipment design dose limits. Furthermore, the applicant also revised LRA Section 4.7.11 and Appendix A.2.4.5.9, indicating that it dispositioned the TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

The applicant also stated that Commitment No.45 is being deleted. The applicant explained that the updating of MEQ files is an internal design control process, and such activity will be tracked via its internal commitment tracking system. The staff noted that, by using the data provided in its response, the applicant has demonstrated that the calculated 60-year total integrated doses for all zones are bounded by the existing equipment design dose limits. Thus, for license renewal, the staff finds the implementation of Commitment No. 45 not necessary.

Based on its review, the staff found the applicant's response to RAI 4.7.11-1b acceptable because the applicant provided data to support its disposition of the TLAA for MEQ and revised LRA Section 4.7.11 and Appendix A.2.4.5.9 to reflect the proper TLAA disposition basis.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis for the MEQ remain valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because, for the normal service radiation exposure in MEQ, the calculated 60-year radiation dose is less than the existing equipment design dose limit.

4.7.11.3 UFSAR Supplement

LRA Section A.2.4.5.9 provides the UFSAR supplement summarizing the MEQ analysis. The staff reviewed LRA Section A.2.4.5.9, consistent with SRP-LR Section 4.7.3.2, which states that the description should contain information associated with the TLAAs regarding the basis for determining that the applicant has made the demonstration required by 10 CFR 54.21(c)(1).

The staff also noted that the applicant previously committed (Commitment No. 45) to revise its MEQ files. Based on the discussions regarding the staff's concern in RAI 4.7.11-1b, the applicant deleted Commitment No. 45 in its letter dated April 22, 2011. The staff found this deletion acceptable, as described in its evaluation of RAI 4.7.11-1b, documented in SER Section 4.7.11.2.

Based on its review of the UFSAR supplement, as amended by letter dated April 22, 2011, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address MEQ analysis, as required by 10 CFR 54.21(d).

4.7.11.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to10 CFR 54.21(c)(1)(i), that the analysis for the MEQ remains 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).

4.7.12 Absence of a TLAA for Metal Corrosion Allowances and Corrosion Effects

4.7.12.1 Summary of Technical Information in the Application

LRA Section 4.7.12 summarizes the absence of TLAA for metal corrosion allowances and corrosion effects. The applicant stated that a review of the Seabrook licensing basis found no description of time-dependent corrosion allowances, rates, or corrosion-dependent design lives of pressure vessels, system components, piping, or metal containment components. The applicant, therefore, concluded that there are no TLAAs for metal corrosion allowances and corrosion effects.

4.7.12.2 Staff Evaluation

The staff reviewed the applicant's TLAA discussion in LRA Section 4.7.12 against the acceptance guidance in SRP-LR Section 4.7.3.1.1 for plant-specific TLAAs, in accordance with 10 CFR 54.21(c)(1)(i). The staff also reviewed UFSAR Section 5.4.2.3, "Steam Generators, Design Evaluation," subsection (d), "Allowable Tube Wall Thinning under All Plant Conditions," which states the following:

> The corrosion rate is based on a conservative weight loss rate of Inconel tubing in flowing 650 °F primary side reactor coolant fluid. The weight loss, when equated to a thinning rate and projected over a 40-year design operating objective, with appropriate reduction after initial hours, is equivalent to 0.083 mils thinning. The assumed corrosion rate of 3 mils leaves a conservative 2.917 mils for general corrosion thinning on the secondary side.

The staff concluded that the above weight loss rate and remaining wall calculations meet the six criteria of TLAAs as identified in the SRP-LR Section 4.1.2. By letter dated January 5, 2011, the staff issued RAI 4.7.12-1, asking that the applicant justify why the metal corrosion allowance for steam generator tube walls is not considered a TLAA.

In its response dated February 3, 2011, the applicant agreed with the staff's conclusion that the time-dependent corrosion associated with the steam generator tubes meets the definition of a TLAA. The applicant revised LRA Section 4.7.12 in its entirety and stated that the linear projection of the tube thinning rate for a 60-year period is equivalent to 0.1245 mils thinning, and, based on the assumed corrosion rate of 3 mils, this leaves 2.8755 mils for general corrosion on the secondary side.

The applicant also revised LRA Table 4.1-1, "Time-Limited Aging Analyses Applicable to Seabrook Station," by including the TLAA for metal corrosion allowance and listing the disposition method as 10 CFR 54.21(c)(1)(i). However, the revised Section 4.7.12 stated the disposition method was 10 CFR 54.21(c)(1)(iii) and also stated that the effects of aging on the intended function(s) will be managed for the period of extended operation by the Steam Generator Tube Integrity Program. The staff noted this discrepancy and, by letter dated March 7, 2011, the staff issued RAI 4.7.12-2, asking the applicant to clarify which method was used to disposition the metal corrosion TLAA.

In its response dated April 5, 2011, the applicant revised Section 4.7.12 again, stating the disposition method is 10 CFR 54.21(c)(1)(i), and the analyses remain valid for the period of extended operation. Based on its review, the staff finds the applicant's response acceptable because the linear projection of the steam generator tube thinning rate to a 60-year period is significantly lower than the assumed corrosion rate of 3 mils. The staff's concerns described in RAIs 4.7.12-1 and 4.7.12-2 are resolved.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis for the metal corrosion allowance for steam generator tube wall remains valid for the period of extended operation. Additionally it meets the acceptance criteria in SRP-LR Section 4.7.3.1.1 because the 60-year thinning rate was compared to the assumed corrosion rate and found to be bounded by the design corrosion rate.

4.7.12.3 UFSAR Supplement

In its response to RAI 4.7.12-1, dated February 3, 2011, the applicant added metal corrosion allowance of steam generator tubes as a TLAA; however, the applicant did not revise LRA Section A.2.4.5, "Other Plant-Specific TLAAs," to include the TLAA for metal corrosion allowances and corrosion effects. By letter dated March 7, 2011, the staff issued RAI 4.7.12-2, asking the applicant to revise LRA Section A.2.4.5 to include the TLAA associated with the steam generator tube metal corrosion allowance.

In its response dated April 5, 2011, the applicant added UFSAR supplement Section A.2.4.5.11 summarizing the metal corrosion allowances and corrosion effects analysis. The staff reviewed LRA Section A.2.4.5.11 consistent with SRP-LR Section 4.7.2.2, which states that the description should contain information associated with the TLAAs regarding the basis for determining that the applicant has made the demonstration required by 10 CFR 54.21(c)(1). Based on its review, the staff finds the applicant's response to RAI 4.7.12-2 acceptable because the UFSAR supplement has been revised to add the TLAA associated with the steam generator tube metal corrosion allowance. The staff's concern described in RAI 4.7.12-2 regarding the UFSAR supplement is resolved.

Based on its review of the UFSAR supplement, included in response to RAI 4.7.12-2, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address metal corrosion allowances and corrosion effects analysis, as required by 10 CFR 54.21(d).

4.7.12.4 Conclusion

On the basis of the review of the LRA and associated RAI responses, the staff concludes that the applicant provided an acceptable demonstration, pursuant to10 CFR 54.21(c)(1)(i), that the analysis for the steam generator tube metal corrosion allowance remains 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).

4.7.13 Absence of a TLAA for Inservice Flaw Growth Analyses that Demonstrate Structural Stability for 40 Years

4.7.13.1 Summary of Technical Information in the Application

LRA Section 4.7.13 addresses the issue of TLAAs related to flaws in ASME Code class components. In this LRA section, the applicant states that Section XI of the ASME Code normally requires a fatigue crack growth rate analysis when flawed components are allowed to remain in service. The applicant also states that these analyses, if performed, could qualify as TLAAs. The applicant indicated that it conducted a review of its licensing basis and identified three fatigue crack growth analyses, which relate to pressurizer nozzle overlays, LBB analyses, and mechanical stress improvement processes (MSIPs) that could qualify as TLAAs. The applicant then provided a description of each potential TLAA in which it indicated that the analysis performed is based on a 60-year plant life and, therefore, is not a TLAA.

4.7.13.2 Staff Evaluation

In its review of LRA Section 4.7.13 the staff considered two issues—the potential existence of additional fatigue crack growth analyses that could be TLAAs and the assertion of the applicant that the identified analyses were not TLAAs because they were conducted to include the period of extended operation. The second aspect of the staff's evaluation consisted of two parts. The first part consisted of verifying that an analysis conducted for 60 years is not a TLAA. The second part consisted of verifying that the analyses under consideration were conducted for a period of 60 years.

In its attempt to identify additional fatigue analyses that could be considered TLAAs, the staff searched the applicant's UFSAR. In this search, the staff did not identify additional fatigue analyses. The staff, therefore, determined that the applicant had identified three fatigue crack growth analyses that could be TLAAs.

In its evaluation of the first aspect of the applicant's assertion that fatigue crack growth evaluations conducted for a period of 60 years are not TLAAs, the staff confirmed that 10 CFR 54.3 states that to be considered a TLAA, calculations must meet six criteria. Criteria 3 states that TLAAs "[i]nvolve time limiting assumptions defined by the current operating term, for example, 40 years." The staff, therefore, determined that the analyses whose assumptions include the period of extended operation, i.e., a plant life of 60 years, are not TLAAs.

In its evaluation of the second aspect of the applicant's assertion that fatigue crack growth evaluations conducted for pressurizer nozzle overlays and MSIP do not constitute TLAAs, the staff noted that these analyses refer to LRA Section 4.3.6. In Section 4.3.6, the applicant states that these analyses were conducted in 2008 and 2009 and were projected through the period of extended operation. The staff, therefore, concludes that these analyses are not TLAAs because the original analyses included the period of extended operation.

In its evaluation of the second aspect of the applicant's assertion that fatigue crack growth evaluations conducted for LBB do not constitute a TLAA, the staff notes that the applicant refers to LRA Section 4.7.3. This section is a description of the LBB TLAA. In this section, the applicant states that "the analyses involved with LBB are considered TLAAs." In Section 4.7.3, the applicant also dispositions this TLAA in accordance with 10 CFR 54.21(c)(1)(i), indicating that the analyses remain valid for the period of extended operation. In its evaluation of the TLAA, the staff noted that the fatigue cycles used in the analysis were based on 40 years. In light of the information presented in LRA Section 4.7.3, it appears to the staff that the LBB TLAA is, in fact, a TLAA that is based on the 40-year current operating term of the plant. It also appears to the staff that, in accordance with SRP-LR paragraph 4.7.3.1.1, the applicant has identified an additional activity, cycle-counting in this case, which allows the assumptions used in the original 40-year calculation to be confirmed for a 60-year plant life. The staff finds that this process allows the TLAA to be applied during the period of operation, but it does not constitute a new calculation based on 60 years. The staff, therefore, disagrees with the applicant's position that the LBB calculations do not constitute a TLAA. To resolve this issue, the staff issued RAI 4.7.13-1 by letter dated December 14, 2010. In this RAI, the staff requested that the applicant modify LRA Section 4.7.13 to indicate that the LBB calculations do constitute a TLAA, which is addressed in LRA Section 4.7.3, or provide justification as to why these calculations do not constitute a TLAA.

In its response dated January 13, 2011, the applicant modified Section 4.7.13 to indicate that LBB calculations are a TLAA, which is addressed in LRA Section 4.7.3. The staff finds the applicant's response acceptable for the following reasons:

- The applicant correctly identifies that the calculations conducted for its LBB analysis constitute a TLAA.
- The applicant appropriately identifies LRA Section 4.7.3 as the location for information concerning this TLAA.
- The information contained within LRA Section 4.7.3 is sufficient to indicate that the LBB analysis is not invalidated by extending the life of the plant from 40–60 years. (The staff's evaluation of the LBB TLAA is contained in Section 4.7.3 of this SER.)

The staff's concern described in RAI 4.7.13-1 is resolved.

4.7.13.3 UFSAR

The staff determined that no UFSAR supplement is required because the applicant addresses fatigue crack growth calculations in the LBB analysis of the RCS primary loop in LRA Section 4.7.3 and the staff's evaluation of the applicant's LBB analysis is contained in SER Section 4.7.3. The staff determined that the removal of this item from this LRA section by the applicant is appropriate and acceptable.

4.7.13.4 Conclusion

On the basis of its review, the staff notes that the applicant has appropriately identified calculations related to three fatigue crack growth analyses (which relate to pressurizer nozzle overlays), LBB analyses, and MSIPs that could be TLAAs.

The applicant addresses fatigue crack growth calculations in the LBB analysis of the RCS primary loop in LRA Section 4.7.3 and the staff's evaluation of the applicant's LBB analysis is contained in SER Section 4.7.3. The staff concludes that the removal of this item from this LRA section by the applicant is appropriate and acceptable.

Pursuant to 10 CFR 54.3, the staff also notes that the applicant has correctly identified that the calculations related to pressurizer nozzle overlays and MSIPs are not TLAAs because they are based on assumptions that include the period of extended operation (see SRP-LR Section 4.3.6). The staff concludes that the manner in which the applicant addressed these items is acceptable.

4.7.14 Diesel Generator Thermal Cycle Evaluation

4.7.14.1 Summary of Technical Information in the Application

LRA Section 4.7.14 describes the applicant's TLAA for the thermal cycling analysis of its emergency diesel generators (EDG), which addresses the equipment qualification in accordance with Institute of Electrical and Electronics Engineers (IEEE) Standard 323, "Qualifying Class 1E Equipment for Nuclear Power Generating Stations." The applicant stated that the OEM conservatively qualified the EDGs for 5,454 full thermal cycles spanning a 40-year design life. The applicant also stated that, based on its current operating practice, it estimates the EDG will be subjected to 2,160 cycles through 60 years of licensed operation, which accounts for maintenance activities, testing activities, and starts during postulated design basis transients and accident events.

The applicant dispositioned the EDG thermal cycling TLAA in accordance with 10 CFR 54.21(c)(1)(i), by indicating the analysis remains valid for the period of extended operation.

4.7.14.2 Staff Evaluation

The staff reviewed LRA Section 4.7.14 and the EDG thermal cycling TLAA to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation. The staff reviewed this TLAA and the corresponding disposition, consistent with SRP-LR Section 4.7.3.1.1, which states that the staff may approve a plant-specific TLAA under 10 CFR 54.21(c)(1)(i) if the applicant can demonstrate that the conditions and assumptions used in the analysis already address the relevant aging effects for the period of extended operation and the acceptance criteria are maintained to provide assurance that the intended function(s) is maintained for renewal.

The applicant compared the number of projected scheduled and unscheduled EDG start cycles to the design limit of 5,454 full thermal cycles. The staff noted that the design limit is supported by the applicant’s equipment qualification evaluation performed in accordance with IEEE Standard 323. However, it was not clear to the staff which design transients would result in a scheduled or unscheduled start of the EDGs. The staff noted that identification of all transients that would initiate a start of the EDGs and the 60-year projections for these transients is needed for comparison to the design limit (5,454 cycles). The staff also noted that LRA Section 4.7.14 did not identify the EDG subcomponent(s) that were qualified in accordance with IEEE Standard 323 or discuss the aging effects that were evaluated in the applicant’s EDG thermal cycling TLAA. The staff noted that a TLAA, defined in accordance with 10 CFR 54.3, must meet six criteria, two of which are the analysis must involve a structure or component that has been scoped in for license renewal in accordance with 10 CFR 54.4, and the analysis must consider an aging effect.

By letter dated January 5, 2011, the staff issued RAI 4.7.14-1, asking that the applicant identify all transients in LRA Table 4.3.1-2 that will result in a scheduled or unscheduled start of the EDGs and any additional transients beyond those in LRA Table 4.3.1-2 that can result in a scheduled or unscheduled start of the EDGs. In addition, the staff asked the applicant to clarify if the projection of the applicable transients that will result in an EDG start was performed on a cumulative transient projection basis or on an individual transient projection basis. In RAI 4.7.14-1, the staff also asked the applicant to do the following:

- identify all relevant EDG subcomponents that were qualified in accordance with IEEE Standard 323
- identify the aging effects that were analyzed in the EDG thermal cycling TLAA
- clarify how the analyzed cycles relate to the aging effect and the applicable acceptance criteria

In its response dated February 3, 2011, the applicant stated that it conservatively included the EDG equipment qualification analysis as a TLAA to account for the number of thermal cycles based on a 40-year period per the original design, even though 10 CFR 54.21(a)(1)(i) does not require AMR for the EDGs. The applicant also stated that the design did not require identification of specific aging effects and that the transients, from LRA Table 4.3.1-2, that may result in an unscheduled start of the EDGs are the loss of load without immediate trip and the loss of offsite power, both having 60-year projections of seven cycles.

The staff noted that, in accordance with Criterion 2 of 10 CFR 54.3, the IEEE Standard 323 analysis for the EDGs did not need to be identified as a TLAA because it does not involve a time-dependent analysis of an aging effect that is applicable to the EDG. The staff determined that the applicant has conservatively identified this analysis as a TLAA.

The applicant concluded that each EDG would not exceed more than 2,160 starts over a 60-year licensed operating period, including allowances for performing maintenance activities on the EDGs and testing after maintenance activities. The staff reviewed LRA Table 4.3.1-3 and noted that there is a significant margin between the numbers of EDG starts that the applicant has conservatively assumed (2,160 starts) when compared to the number of starts assumed in the EDG equipment qualification analysis (5,454 cycles).

Based on this review, the staff finds that, consistent with SRP-LR 4.7.3.1.1, the applicant's response to RAI 4.7.14-1 is acceptable because the applicant is conservatively treating the EDG thermal cycle analysis as a TLAA, and there is sufficient margin between the conservatively assumed EDG starts for 60-years of operation and the analyzed number of EDG starts. The staff's concerns described in RAI 4.7.14-1 are resolved.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the TLAA for EDG thermal cycle analysis remains valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.3.1.1 because the applicant has adequately demonstrated that the total number of EDG starts, as projected through 60 years of operation, will be less than the 5,454 EDG starts analyzed in the in the EDG equipment qualification analysis.

4.7.14.3 UFSAR Supplement

LRA Section A.2.4.5.10 provides the UFSAR supplement summarizing the TLAA for the thermal cycling analysis of the EDGs, addressing the equipment qualification in accordance with IEEE Standard 323. The staff reviewed LRA Section A.2.4.5.10, consistent with SRP-LR Section 4.7.3.2, to verify that it contains information that the TLAA has been dispositioned for the period of extended operation.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address the TLAA for the thermal cycling analysis of EDGs under its equipment qualification, in accordance with IEEE Standard 323, as required by 10 CFR 54.21(d).

4.7.14.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the EDG thermal cycling TLAA remains 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).

4.7.15 Steam Generator Tube Wall Wear from Flow-Induced Vibration

4.7.15.1 Summary of Technical Information in the Application

By letter dated February 3, 2011, the applicant amended its LRA to include LRA Section 4.7.15, in response to RAIs 4.3.5-1 and 4.3.5-2, to describe the applicant's TLAA for steam generator tube wear from FIV. The applicant stated that its Model F steam generators were evaluated for tube wear from FIV for the 7.4 percent power increase implemented as part of its Power Uprate Project. The applicant further stated that the uprate analysis for the effects of FIV on steam generator tube wear assumed 40 years of operation, and the maximum predicted tube wall wear for a 40-year operating life was estimated to be 0.0032 in. for the pre-uprate conditions. The applicant also stated that the 7.4 percent power uprate resulted in an increase of the maximum 40-year tube wall wear of 0.0050 in. The applicant projected the maximum 60-year tube wall wear to be 0.0075 in, (approximately 20 percent through-wall wear) based on a linear projection, and it concluded that the projected wear is less than the limit of acceptability of 40 percent of wall thickness. The applicant dispositioned the steam generator tube wear from FIV TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.7.15.2 Staff Evaluation

The staff reviewed LRA Subsection 4.7.15 and the TLAA for steam generator tube wear from FIV to verify, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation. The staff reviewed the applicant's TLAA and the corresponding disposition consistent with SRP-LR Section 4.7.3.1.1. The SRP-LR states that the staff may accept the applicant's basis if the conditions and assumptions used in the analysis already address the relevant aging effects for the period of extended operation and acceptance criteria are maintained to provide assurance that the intended function(s) is maintained.

As described previously in SER Section 4.3.5, the staff issued RAI 4.3.5-1, Request 1, by letter dated January 5, 2011. This RAI requested that the applicant provide its technical basis to support the linear extrapolation method for wear of the steam generator tubes and to demonstrate that its analysis bounds likely changes in wear (and fatigue) over the period of extended operation, as affected by FIV or fluid-structure interactions. The staff also asked the applicant to identify any past or future planned independent confirmation to ensure the validity of the analyses, and the adequacy of the confirmation for the period of extended operation.

In its response to RAI 4.3.5-1, Request 1, dated February 3, 2011, the applicant stated that a linear tube wall wear rate is considered reasonable to determine a 60-year projection for tube wear. The applicant also stated that confirmation of the validity of the analyses to determine tube wear is provided in the Eddy Current Inspection Program described in its Steam Generator Tube Integrity Program. The applicant stated that, as discussed in the NRC SE for Amendment No. 101 for the Seabrook, Unit No. 1, 5.2 percent Power Uprate (ADAMS Accession No. ML050140453), any increase in wear would progress over many cycles and would be readily observed during routine eddy current inspections. The applicant revised the LRA to include this as a clarification in support of its TLAA disposition. The applicant further amended the disposition from 10 CFR 54.21(c)(1)(i) to 10 CFR 54.21(c)(1)(iii) to reflect that this aging effect will be managed by the Steam Generator Tube Integrity Program.

The staff noted that steam generator tube wear-rate is typically decreasing (i.e., tube wear decrease with time). Thus, the staff finds the applicant's use of linear tube wear projection from

40-year to 60-year operating period conservative and acceptable because the linear projection would result in a higher tube wear estimate than the actual tube wear, and hence RAI 4.3.5-1, Request 1, is resolved.

In its responses to RAI 4.3.5-1 and RAI 4.3.5-2, by letter dated February 3, 2011, the applicant stated that the basis for its disposition of this TLAA was the stretch power uprate (SPU) previously approved in the staff's SER dated February 28, 2005 (ADAMS Accession No. ML050140453). The staff noted that the applicant subsequently received a 1.7 percent measurement uncertainty recapture approval on May 22, 2006 (ADAMS Accession No. ML061360034). The staff noted that the SPU approved in the staff's SER is for 5.2 percent power increase, and it was discussed in LRA Section 4.3.5, as amended by letter dated February 3, 2011. The staff's review and evaluation of RAI 4.3.5-1 and RAI 4.3.5-2 are documented in SER 4.3.5.2. However, LRA Section 4.7.15 indicated that the power uprate was 7.4 percent. In the staff's SER for SPU, tube wear increased from approximately 0.003 in. to approximately 0.005 in. at the 5.2 percent uprated condition.

By letter dated March 30, 2011, the staff issued followup RAI 4.7.15-1, asking the applicant to clarify or reconcile the actual power uprate applicable for the period of extended operation and provide an updated UFSAR supplement section in LRA Appendix A commensurate with the new LRA Section 4.7.15. In its response dated April 22, 2011, the applicant revised LRA Section 4.7.15 to show that the actual thermal power is 3,648 megawatts thermal, which was achieved after the SPU and measurement uncertainty recapture were implemented. The applicant also revised Appendix A.2.4.5.12 to show that it dispositioned the TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation. The staff noted that the applicant removed the references to conflicting percentage values for the power uprate in the LRA. Based on its review, the staff found the applicant's response to RAI 4.7.15-1 acceptable because the applicant revised LRA Section 4.7.11 to reflect the actual thermal power and Appendix A.2.4.5.12 to reflect the TLAA disposition basis.

The staff noted that the maximum 40-year tube wall wear is 0.0050 in. and the applicant calculated the projected 60-year tube wall wear by multiplying the 40-year wear of 0.0050 in. by a factor 1.5. The staff noted that resulting tube wall wear of 0.0075 in. (approximately 20 percent) remains less than the design limit of 40 percent wall thickness. Furthermore, the staff noted that steam generator tube wear-rate is typically decreasing (i.e., tube-wearing decrease with time). Thus, the staff finds the applicant's use of linear tube-wearing projection from 40-year to 60-year operating period conservative and acceptable because the linear projection would result in a higher tube wear estimate than the actual tube wear.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for steam generator tube wall wear from FIV remain valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because, for the steam generator tube, the 60-year wall thinning due to FIV is within the acceptable design wall thickness limit.

4.7.15.3 UFSAR Supplement

LRA Section A.2.4.5.12, as amended by letter dated April 22, 2011, provides the UFSAR supplement summarizing the analysis of steam generator tube wall wear due to FIV. The staff reviewed LRA Section A.2.4.5.12, consistent with SRP-LR Section 4.7.3.2, which states that the description should contain information associated with the TLAAs regarding the basis for determining that the applicant has made the demonstration required by 10 CFR 54.21(c)(1).

Based on its review of the amended UFSAR supplement, the staff finds the supplement meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determined that the applicant provided an adequate summary description of its actions to address the analysis for steam generator tube wall wear from FIV, as required by 10 CFR 54.21(d).

4.7.15.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis for steam generator tube wall wear from FIV remains 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).

4.8 Conclusion

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 provided a sufficient list of TLAAs, as defined in 10 CFR 54.3, and that the applicant has demonstrated the following:

- The TLAAs will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i),
- 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
- 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 supplements for the TLAAs and finds that, the supplements contain 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. Additionally, 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

In accordance with Title 10, Part 54, of the *Code of Federal Regulations*, the safety evaluation report (SER) will be referred to the Advisory Committee on Reactor Safeguards (ACRS), which will review the license renewal application (LRA) for Seabrook Station, Unit 1. The ACRS Subcommittee on Plant License Renewal will conduct its detailed review of the LRA after this SER is issued. NextEra Energy Seabrook, LLC (the applicant) and the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) will meet with the ACRS subcommittee and the ACRS full committee to discuss issues associated with the review of the LRA.

After the ACRS completes its review of the LRA and SER, the full committee will issue a report discussing results of its review. An update to this SER will include the ACRS report and the staff's response to any issues and concerns reported.

SECTION 6

CONCLUSION

The staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) reviewed the license renewal application (LRA) for Seabrook Station Unit 1, 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, pending resolution of the open and confirmatory items, the requirements of 10 CFR 54.29(a) will be met.

The staff notes that any requirements of 10 CFR Part 51, Subpart A, will be documented in a supplement to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS)."

APPENDIX A

Seabrook Station License Renewal Commitments

During the review of the Seabrook Station Unit 1 license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff), NextEra Energy Seabrook, LLC (the applicant) made commitments related to managing the effects of aging for structures and components. Table A-1 lists these commitments along with the implementation schedules and sources for each commitment.

Table A-1. Seabrook Station License Renewal Commitments

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/LRA Section	Enhancement or Implementation Schedule
1) PWR Vessel Internals	An inspection plan for Reactor Vessel Internals will be submitted for NRC review and approval.	A.2.1.7	Program to be implemented prior to the period of extended operation. Inspection plan to be submitted to NRC not later than 2 years after receipt of the renewed license or not less than 24 months prior to the period of extended operation, whichever comes first.
2) Closed-Cylce Cooling Water	Enhance the program to include visual inspection for cracking, loss of material and fouling when the in-scope systems are opened for maintenance.	A.2.1.12	Prior to the period of extended operation
3) Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Enhance the program to monitor general corrosion on the crane and trolley structural components and the effects of wear on the rails in the rail system.	A.2.1.13	Prior to the period of extended operation
4) Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Enhance the program to list additional cranes for monitoring.	A.2.1.13	Prior to the period of extended operation
5) Compressed Air Monitoring	Enhance the program to include an annual air quality test requirement for the Diesel Generator compressed air sub system.	A.2.1.14	Prior to the period of extended operation
6) Fire Protection	Enhance the program to perform visual inspection of penetration seals by a fire protection qualified inspector.	A.2.1.15	Prior to the period of extended operation.
7) Fire Protection	Enhance the program to add inspection requirements such as spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates by qualified inspector.	A.2.1.15	Prior to the period of extended operation.
8) Fire Protection	Enhance the program to include the performance of visual inspection of	A.2.1.15	Prior to the period of extended

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/LRA Section	Enhancement or Implementation Schedule
	fire-rated doors by a fire protection qualified inspector.		operation.
9) Fire Water System	Enhance the program to include NFPA 25 guidance for “where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing”.	A.2.1.16	Prior to the period of extended operation.
10) Fire Water System	Enhance the program to include the performance of periodic flow testing of the fire water system in accordance with the guidance of NFPA 25.	A.2.1.16	Prior to the period of extended operation.
11) Fire Water System	Enhance the program to include the performance of periodic visual or volumetric inspection of the internal surface of the fire protection system upon each entry to the system for routine or corrective maintenance. These inspections will be documented and trended to determine if a representative number of inspections have been performed prior to the period of extended operation. If a representative number of inspections have not been performed prior to the period of extended operation, focused inspections will be conducted. These inspections will be performed within ten years prior to the period of extended operation.	A.2.1.16	Within ten years prior to the period of extended operation.
12) Aboveground Steel Tanks	Enhance the program to include components and aging effects required by the Aboveground Steel Tanks.	A.2.1.17	Prior to the period of extended operation.
13) Aboveground Steel Tanks	Enhance the program to include an ultrasonic inspection and evaluation of the internal bottom surface of the two Fire Protection Water Storage Tanks.	A.2.1.17	Within ten years prior to the period of extended operation.
14) Fuel Oil Chemistry	Enhance program to add requirements to 1) sample and analyze new fuel deliveries for biodiesel prior to offloading to the Auxiliary Boiler fuel oil storage tank and 2) periodically sample stored fuel in the Auxiliary Boiler fuel oil storage tank.	A.2.1.18	Prior to the period of extended operation.
15) Fuel Oil Chemistry	Enhance the program to add requirements to check for the presence of water in the Auxiliary Boiler fuel oil storage tank at least once per quarter and to remove water as necessary.	A.2.1.18	Prior to the period of extended operation.
16) Fuel Oil Chemistry	Enhance the program to require draining, cleaning and inspection of the diesel fire pump fuel oil day tanks on a frequency of at least once every ten years.	A.2.1.18	Prior to the period of extended operation.

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/LRA Section	Enhancement or Implementation Schedule
17) Fuel Oil Chemistry	Enhance the program to require ultrasonic thickness measurement of the tank bottom during the 10-year draining, cleaning and inspection of the Diesel Generator fuel oil storage tanks, Diesel Generator fuel oil day tanks, diesel fire pump fuel oil day tanks and auxiliary boiler fuel oil storage tank.	A.2.1.18	Prior to the period of extended operation.
18) Reactor Vessel Surveillance	Enhance the program to specify that all pulled and tested capsules, unless discarded before August 31, 2000, are placed in storage.	A.2.1.19	Prior to the period of extended operation.
19) Reactor Vessel Surveillance	Enhance the program to specify that if plant operations exceed the limitations or bounds defined by the Reactor Vessel Surveillance Program, such as operating at a lower cold leg temperature or higher fluence, the impact of plant operation changes on the extent of Reactor Vessel embrittlement will be evaluated and the NRC will be notified.	A.2.1.19	Prior to the period of extended operation.
20) Reactor Vessel Surveillance	Enhance the program as necessary to ensure the appropriate withdrawal schedule for capsules remaining in the vessel such that one capsule will be withdrawn at an outage in which the capsule receives a neutron fluence that meets the schedule requirements of 10 CFR 50 Appendix H and ASTM E185-82 and that bounds the 60-year fluence, and the remaining capsule(s) will be removed from the vessel unless determined to provide meaningful metallurgical data.	A.2.1.19	Prior to the period of extended operation.
21) Reactor Vessel Surveillance	Enhance the program to ensure that any capsule removed, without the intent to test it, is stored in a manner which maintains it in a condition which would permit its future use, including during the period of extended operation.	A.2.1.19	Prior to the period of extended operation.
22) One-Time Inspection	Implement the One Time Inspection Program.	A.2.1.20	Within ten years prior to the period of extended operation.
23) Selective Leaching of Materials	Implement the Selective Leaching of Materials Program. The program will include a one-time inspection of selected components where selective leaching has not been identified and periodic inspections of selected components where selective leaching has been identified.	A.2.1.21	Within five years prior to the period of extended operation.
24) Buried Piping And Tanks Inspection	Implement the Buried Piping And Tanks Inspection Program.	A.2.1.22	Within ten years prior to entering the period of extended operation
25) One-Time Inspection of	Implement the One-Time Inspection of ASME Code Class 1 Small Bore-	A.2.1.23	Within ten years prior to the period

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/LRA Section	Enhancement or Implementation Schedule
ASME Code Class 1 Small Bore-Piping	Piping Program.		of extended operation.
26) External Surfaces Monitoring	Enhance the program to specifically address the scope of the program, relevant degradation mechanisms and effects of interest, the refueling outage inspection frequency, the inspections of opportunity for possible corrosion under insulation, the training requirements for inspectors and the required periodic reviews to determine program effectiveness.	A.2.1.24	Prior to the period of extended operation.
27) Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.	A.2.1.25	Prior to the period of extended operation.
28) Lubricating Oil Analysis	Enhance the program to add required equipment, lube oil analysis required, sampling frequency, and periodic oil changes.	A.2.1.26	Prior to the period of extended operation.
29) Lubricating Oil Analysis	Enhance the program to sample the oil for the Switchyard SF6 compressors and the Reactor Coolant pump oil collection tanks.	A.2.1.26	Prior to the period of extended operation.
30) Lubricating Oil Analysis	Enhance the program to require the performance of a one-time ultrasonic thickness measurement of the lower portion of the Reactor Coolant pump oil collection tanks prior to the period of extended operation.	A.2.1.26	Prior to the period of extended operation.
31) ASME Section Xi, Subsection IWL	Enhance procedure to include the definition of “Responsible Engineer”.	A.2.1.28	Prior to the period of extended operation.
32) Structures Monitoring Program	Enhance procedure to add the aging effects, additional locations, inspection frequency and ultrasonic test requirements.	A.2.1.31	Prior to the period of extended operation.
33) Structures Monitoring Program	Enhance procedure to include inspection of opportunity when planning excavation work that would expose inaccessible concrete.	A.2.1.31	Prior to the period of extended operation.
34) Electrical Cables and Connections Not	Implement the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program.	A.2.1.32	Prior to the period of extended operation.

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/LRA Section	Enhancement or Implementation Schedule
Subject to 10 CFR 50.49 Environmental Qualification Requirements			
35) Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Implement the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program.	A.2.1.33	Prior to the period of extended operation.
36) Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Implement the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program.	A.2.1.34	Prior to the period of extended operation.
37) Metal Enclosed Bus	Implement the Metal Enclosed Bus program.	A.2.1.35	Prior to the period of extended operation.
38) Fuse Holders	Implement the Fuse Holders program.	A.2.1.36	Prior to the period of extended operation.
39) Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Implement the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program.	A.2.1.37	Prior to the period of extended operation.
40) 345 KV SF6	Implement the 345 KV SF6 Bus program.	A.2.2.1	Prior to the period of extended

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/LRA Section	Enhancement or Implementation Schedule
Bus Program			operation.
41) Metal Fatigue of Reactor Coolant Pressure Boundary	Enhance the program to include additional transients beyond those defined in the Technical Specifications and UFSAR.	A.2.3.1	Prior to the period of extended operation.
42) Metal Fatigue of Reactor Coolant Pressure Boundary	Enhance the program to implement a software program, to count transients to monitor cumulative usage on selected components.	A.2.3.1	Prior to the period of extended operation.
43) Pressure - Temperature Limits, including Low Temperature Overpressure Protection Limits	Seabrook Station will submit updates to the P-T curves and LTOP limits to the NRC at the appropriate time to comply with 10 CFR 50 Appendix G.	A.2.4.1.4	The updated analyses will be submitted at the appropriate time to comply with 10 CFR 50 Appendix G, Fracture Toughness Requirements.

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/LRA Section	Enhancement or Implementation Schedule
44) Environmentally - Assisted Fatigue Analyses (TLAA)	NextEra Seabrook will perform a review of design basis ASME 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 Seabrook 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 the limiting location identified consists of nickel alloy, the environmentally-assisted fatigue calculation for nickel alloy will be performed using the rules of NUREG/CR-6909. (1) Consistent with the Metal Fatigue of Reactor Coolant Pressure Boundary Program Seabrook Station will update the fatigue usage calculations using refined fatigue analyses, if necessary, to determine acceptable CUFs (i.e., less than 1.0) when accounting for the effects of the reactor water environment. This includes applying the appropriate Fen factors to valid CUFs determined from an existing fatigue analysis valid for the period of extended operation or from an analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case). (2) If acceptable CUFs cannot be demonstrated for all the selected locations, then additional plant-specific locations will be evaluated. For the additional plant-specific locations, if CUF, including environmental effects is greater than 1.0, then Corrective Actions will be initiated, in accordance with the Metal Fatigue of Reactor Coolant Pressure Boundary Program, B.2.3.1. Corrective Actions will include inspection, repair, or replacement of the affected locations before exceeding a CUF of 1.0 or the effects of fatigue will be managed by an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC).	A.2.4.2.3	At least two years prior to entering the period of extended operation.
45	Number Not Used		
46) Protective Coating Monitoring and Maintenance	Enhance the program by designating and qualifying an Inspector Coordinator and an Inspection Results Evaluator.	A.2.1.38	Prior to the period of extended operation

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/LRA Section	Enhancement or Implementation Schedule
47) Protective Coating Monitoring and Maintenance	Enhance the program by including, “Instruments and Equipment needed for inspection may include, but not be limited to, flashlight, spotlights, marker pen, mirror, measuring tape, magnifier, binoculars, camera with or without wide angle lens, and self sealing polyethylene sample bags.”	A.2.1.38	Prior to the period of extended operation
48) Protective Coating Monitoring and Maintenance	Enhance the program to include a review of the previous two monitoring reports.	A.2.1.38	Prior to the period of extended operation
49) Protective Coating Monitoring and Maintenance	Enhance the program to require that the inspection report is to be evaluated by the responsible evaluation personnel, who is to prepare a summary of findings and recommendations for future surveillance or repair.	A.2.1.38	Prior to the period of extended operation
50) ASME Section XI, Subsection IWE	Perform UT testing of the containment liner plate in the vicinity of the moisture barrier for loss of material.	A.2.1.27	No later than December 31, 2015 and repeated at intervals of no more than five refueling outages
51)	Number not used		
52) ASME Section XI, Subsection IWL	Implement measures to maintain the exterior surface of the Containment Structure, from elevation -30 feet to +20 feet, in a dewatered state.	A.2.1.28	By 2013
53) Reactor Head Closure Studs	Replace the spare reactor head closure stud(s) manufactured from the bar that has a yield strength > 150 ksi with ones that do not exceed 150 ksi.	A.2.1.3	Prior to the period of extended operation.
54) Steam Generator Tube Integrity	Unless an alternate repair criteria changing the ASME code boundary is permanently approved by the NRC, or the Seabrook Station steam generators are changed to eliminate PWSCC-susceptible tube-to-tubesheet welds, submit a plant-specific aging management program to manage the potential aging effect of cracking due to PWSCC at least twenty-four months prior to entering the Period of Extended Operation.	A.2.1.10	Program to be submitted to NRC at least 24 months prior to the period of extended operation.
55) Steam Generator Tube Integrity	Seabrook will perform an inspection of each steam generator to assess the condition of the divider plate assembly.	A.2.1.10	Prior to entering the period of extended operation
56) Closed-Cycle Cooling Water System	Revise the station program documents to reflect the EPRI Guideline operating ranges and Action Level values for hydrazine and sulfates.	A.2.1.12	Prior to entering the period of extended operation.

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/LRA Section	Enhancement or Implementation Schedule
57) Closed-Cycle Cooling Water System	Revise the station program documents to reflect the EPRI Guideline operating ranges and Action Level values for Diesel Generator Cooling Water Jacket pH.	A.2.1.12	Prior to entering the period of extended operation.
58) Fuel Oil Chemistry	Update Technical Requirement Program 5.1, (Diesel Fuel Oil Testing Program) ASTM standards to ASTM D2709-96 and ASTM D4057-95 required by the GALL XI.M30 Rev 1	A.2.1.18	Prior to the period of extended operation.
59) Nickel Alloy Nozzles and Penetrations	The Nickel Alloy Aging Nozzles and Penetrations program will implement applicable Bulletins, Generic Letters, and staff accepted industry guidelines.	A.2.2.3	Prior to the period of extended operation.
60) Buried Piping and Tanks Inspection	Implement the design change replacing the buried Auxiliary Boiler supply piping with a pipe-within-pipe configuration with leak indication capability.	A.2.1.22	Prior to entering the period of extended operation.
61) Compressed Air Monitoring Program	Replace the flexible hoses associated with the Diesel Generator air compressors on a frequency of every 10 years.	A.2.1.14	Within ten years prior to entering the period of extended operation.
62) Water Chemistry	Enhance the program to include a statement that sampling frequencies are increased when chemistry action levels are exceeded.	A.2.1.2	Prior to entering the period of extended operation.
63) Flow Induced Erosion	Ensure that the quarterly CVCS Charging Pump testing is continued during the PEO. Additionally, add a precaution to the test procedure to state that an increase in the CVCS Charging Pump mini flow above the acceptance criteria may be indicative of erosion of the mini flow orifice as described in LER 50-275/94-023.	N/A	Prior to the period of extended operation
64) Buried Piping and Tanks Inspection	Soil analysis shall be performed prior to entering the period of extended operation to determine the corrosivity of the soil in the vicinity of non-cathodically protected steel pipe within the scope of this program. If the initial analysis shows the soil to be non-corrosive, this analysis will be re-performed every ten years thereafter.	A.2.1.22	Prior to entering the period of extended operation.
65) Flux Thimble Tube	Implement measures to ensure that the movable incore detectors are not returned to service during the period of extended operation.	N/A	Prior to entering the period of extended operation
66	Number not used		
67) Structures Monitoring	Perform one shallow core bore in an area that was continuously wetted from borated water to be examined for concrete degradation and also		No later than December 31, 2015

Item Number	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Section/LRA Section	Enhancement or Implementation Schedule
Program	exposed rebar to detect any degradation such as loss of material.		
68) Structures Monitoring Program	Perform sampling at the leakoff collection points for chlorides, sulfates, pH and iron once every three months.		Starting January 2014

APPENDIX B

CHRONOLOGY

This appendix lists chronologically the routine licensing correspondence between the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) and NextEra Energy Seabrook, LLC (the applicant). This appendix also lists other correspondence on the staff's review of the Seabrook Station Unit 1 (Seabrook) license renewal application (LRA) (under Docket No. 50-443).

Date	Subject
5/25/2010	License Renewal Application for Facility Operating License (Amend/Renewal), NextEra Energy Seabrook, LLC, Seabrook Station—License Renewal Application, Volume I (Agencywide Document Access and Management System (ADAMS) Accession No. ML101590098)
5/25/2010	License Renewal Application for Facility Operating License (Amend/Renewal), NextEra Energy Seabrook, LLC, Seabrook Station—License Renewal Application, Volume II (ADAMS Accession No. ML101590101)
5/25/2010	License Renewal Application for Facility Operating License (Amend/Renewal), NextEra Energy Seabrook, LLC, Seabrook Station—License Renewal Application, Volume III. (ADAMS Accession No. ML101590091)
6/10/2010	Letter from Holian, B.E., NRC, to Freeman, P., NextEra Energy Seabrook, LLC: Receipt and Availability of the License Renewal Application for the Seabrook Station Nuclear Power Plant(ADAMS Accession No. ML101320273)
6/10/2010	Federal Register Notice, from Holian, B.E., NRC: Notice of Receipt and Availability for Seabrook Station License Renewal Application—FRN (ADAMS Accession No. ML101330049)
7/13/2010	Letter from Holian B.E., NRC, to Freeman, P., NextEra Energy Seabrook, LLC: Determination of Acceptability and Sufficiency for Docketing, Proposed Review Schedule, and Opportunity for a Hearing Regarding the Application from NextEra Energy Seabrook, LLC, for Renewal of the Operating License for Seabrook Station, Unit 1 (ADAMS Accession No. ML101690417)
7/13/2010	Federal Register Notice, from Holian B.E., NRC: Notice of Acceptance for Docketing of the Application and Notice of Opportunity for Hearing Regarding Renewal of Facility Operating License No. NPF-086 for an Additional 20-year Period for License Renewal for Seabrook Station—FRN (ADAMS Accession No. ML101690449)
7/16/2010	Summary of Telephone Conference Call Held on June 24, 2010, Between NRC and NextEra Energy Seabrook, LLC, Concerning the Review of Acceptability of Docketing of the Seabrook Station, Unit 1, License Renewal Application (ADAMS Accession No. ML101800207)
7/19/2010	Slides and Viewgraphs, from Plasse, R.A., NRC, Seabrook Station License Renewal Process Overview (ADAMS Accession No. ML101970370)
7/20/2010	Meeting Notice, from Plasse, R.A., NRC, to Pham, B.M., NRC, August 19, 2010, Forthcoming Meeting to Discuss the License Renewal Process and Environmental Scoping for Seabrook Station License Renewal Application Review (ADAMS Accession No. ML101900013)
8/4/2010	Press Release, NRC, Press Release-I-10-036: NRC to Discuss Process for Review of License Renewal Application for Seabrook Nuclear Plant, Seek Input on Environmental Review (ADAMS Accession No. ML102160633)

Date	Subject
8/10/2010	Meeting Briefing Package/Handouts, from Susco, J.J., NRC, Seabrook Station License Renewal Process Overview and Environmental Impact Statement Scoping Public Meeting Slides (ADAMS Accession No. ML102220430)
8/10/2010	Slides and Viewgraphs, from Plasse, R.A., NRC, Seabrook Station License Renewal Process Overview and Scoping Public Meeting Slides (ADAMS Accession No. ML102220571)
9/20/2010	Memoranda, from Susco, J.J., NRC, to NextEra Energy Seabrook, LLC, Summary of Public License Renewal Overview and Environmental Scoping Meeting Related to the Review of the Seabrook Station License Renewal Application (TAC Nos. ME3959 and ME4028) (ADAMS Accession No. ML102520222)
10/29/2010	Letter from Freeman, P.O., NextEra Energy Seabrook, LLC: Seabrook Station—Supplement to License Renewal Application (ADAMS Accession No. ML103060022)
11/10/2010	Press Release, NRC, Press Release-10-206: Licensing Board to Hear Oral Argument Nov. 30 in Portsmouth, NH, on Seabrook Nuclear Power Plant License Renewal (ADAMS Accession No. ML103160148)
11/15/2010	Letter from Freeman, P.O., NextEra Energy Seabrook, LLC: Seabrook Station—Supplement 2 to License Renewal Application (ADAMS Accession No. ML103210330)
11/18/2010	Letter to Freeman, P., NextEra Energy Seabrook, LLC: Request for Additional Information Related to the Review of the Seabrook Station, License Renewal Application (TAC No. ME4028) (ADAMS Accession No. ML103090308)
11/18/2010	Letter to Freeman, P., NextEra Energy Seabrook, LLC: Request for Additional Information Related to the Review of the Seabrook Station, License Renewal Application—Aging Management Programs (ADAMS Accession No. ML103090558)
11/18/2010	Letter to Freeman, P., NextEra Energy Seabrook, LLC: Request for Additional Information Related to the Review of the Seabrook Station License Renewal Application (TAC No. ME4028) (ADAMS Accession No. ML103130159)
12/3/2010	Letter from Freeman, P.O., NextEra Energy Seabrook, LLC: Seabrook Station: Response to Request for Additional Information NextEra Energy Seabrook License Renewal Application (ADAMS Accession No. ML103400259)
12/14/2010	Letter to Freeman, P., NextEra Energy Seabrook, LLC: Request for Additional Information Related to the Review of the Seabrook Station, License Renewal Application (TAC No. ME4028)—Aging Management Programs (ADAMS Accession No. ML103260554)
12/14/2010	Letter to Freeman, P., NextEra Energy Seabrook, LLC: Request for Additional Information Related to the Review of The Seabrook Station, License Renewal Application (TAC No. ME4028)—Aging Management Programs (ADAMS Accession No. ML103420273)
12/17/2010	Letter from Freeman, P.O., NextEra Energy Seabrook, LLC: Response to Request for Additional Information NextEra Energy Seabrook License Renewal Application Aging Management Programs (ADAMS Accession No. ML103540534)
12/22/2010	Letter from Freeman, P.O., NextEra Energy Seabrook, LLC: Response to Request for Additional Information Set 2 Related to the Review of the License Renewal Application (ADAMS Accession No. ML103620313)
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APPENDIX C

PRINCIPAL CONTRIBUTORS

This appendix lists the principal contributors for the development of this safety evaluation report (SER) and their areas of responsibility.

Name	Responsibility
Alley, David	Reviewer—Mechanical
Armstrong, Garry	Reviewer—Mechanical
Auluck, Raj	Management Oversight
Brittner, Don	Reviewer—Mechanical
Buford, Angela	Reviewer—Structural
Casto, Greg	Management Oversight
Cunanan, Arthur	Management Oversight
Daily, John	Management Oversight
Dennig, Robert	Management Oversight
Doutt, Cliff	Reviewer—Electrical
Dozier, Jerry	Management Oversight
Erickson, Alice	Reviewer—Structural
Foli, Adakou	Reviewer—Electrical
Fu, Bart	Reviewer—Mechanical
Gardner, William	Management Oversight
Gardocki, Stanley	Reviewer—Mechanical
Gavula, Jim	Reviewer—Mechanical
Green, Kim	Management Oversight
Hiser, Allen	Management Oversight
Holian, Brian	Management Oversight
Holston, Bill	Reviewer—Mechanical
Hunt, Chris	Reviewer—Mechanical
Iqbal, Naeem	Reviewer—Fire Protection
Kalikian, Roger	Reviewer—Mechanical
Khanna, Meena	Management Oversight
Kichline, Michelle	Reviewer—Mechanical
Klein, Alex	Management Oversight
Klos, John	Reviewer—Mechanical
Lehman, Bryce	Reviewer—Structural

Name	Responsibility
Li, Rui	Reviewer—Electrical
Lupold, Tim	Management Oversight
Manoly, Kamal	Reviewer—Structural
Medoff, Jim	Reviewer—Mechanical
Miller, Kenneth	Reviewer—Electrical
Min, Seung	Reviewer—Mechanical
Mitchell, Matt	Management Oversight
Ng, Ching	Reviewer—Mechanical
Nguyen, Duc	Reviewer—Electrical
Obodoako, Alyoysius	Reviewer—Mechanical
Parks, Benjamin	Reviewer—Neutron Fluence
Pelton, Dave	Management Oversight
Plasse, Rick	Project Management
Prinaris, Andrew	Reviewer—Structural
Rhow, Sang	Reviewer—Electrical
Rogers, Bill	Reviewer—Scoping & Screening Methodology
Sallman, Ahsan	Reviewer—Mechanical
Sheikh, Abdul	Reviewer—Structural
Smith, Ed	Reviewer— Scoping & Screening Methodology
Sun, Robert	Reviewer—Mechanical
Taylor, Robert	Management Oversight
Torres, Roberto	Reviewer—Mechanical
Ulses, Anthony	Management Oversight
Uribe, Juan	Reviewer—Mechanical
Vaucher, Rachel	Reviewer—Mechanical
Wentzel, Mike	Management Oversight
Wilson, George	Management Oversight
Wise, John	Reviewer—Mechanical
Wong, Albert	Reviewer—Mechanical
Wong, Emma	Reviewer—Mechanical
Wrona, Dave	Management Oversight
Yee, On	Reviewer—Mechanical
Contractors	
Argonne National Laboratory	Technical Review
Ian, Evan & Alexander Corporation	SER Support

APPENDIX D

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This appendix lists the references used throughout this safety evaluation report (SER) for review of the license renewal application (LRA) for Seabrook Station Unit 1.

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